Integrated Reliability.

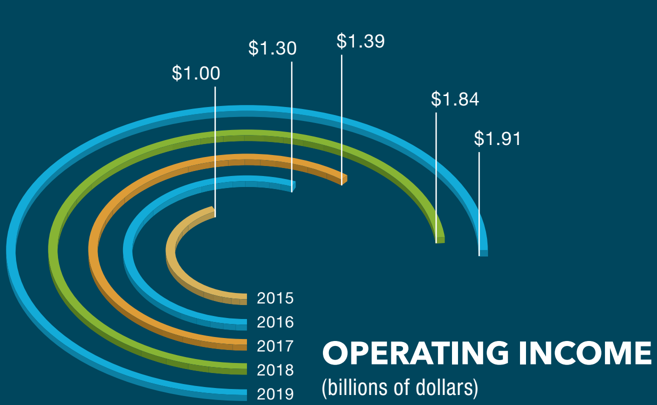
ONEOK 2019 ANNUAL REPORT

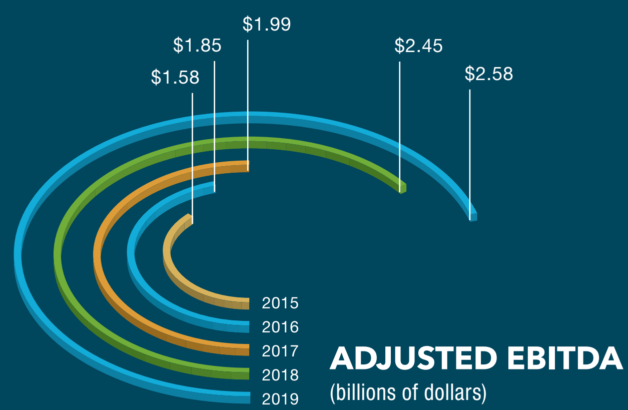
ONEOK

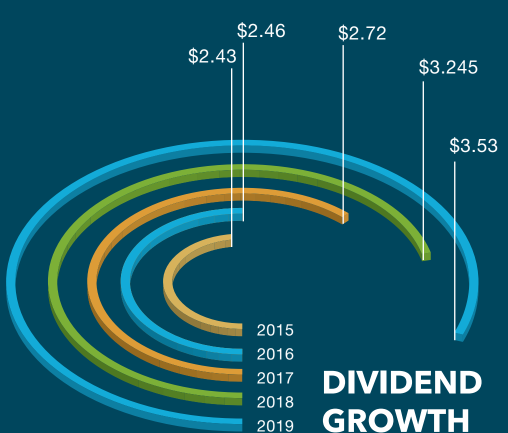
ONEOK, Inc. (pronounced ONE-OAK) (NYSE: OKE) is a leading midstream service provider and owner of one of the nation's premier natural gas liquids (NGL) systems, connecting NGL supply in the Rocky Mountain, Permian and Mid-Continent regions with key market centers and an extensive network of natural gas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

ONEOK is a FORTUNE 500 company and is included in the S&P 500. For the latest news about ONEOK, find us on LinkedIn, Facebook, Twitter and Instagram.

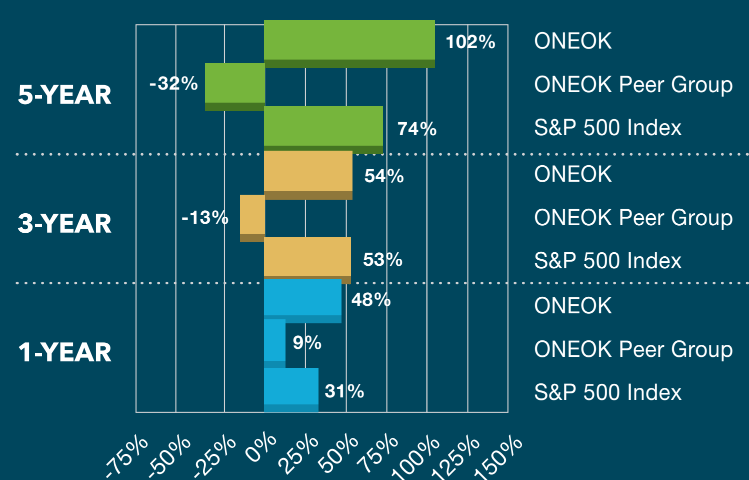
Financial Performance







TOTAL SHAREHOLDER RETURN*



As of Dec. 31, 2019
*Total return represents share-price appreciation and the reinvestment of dividends.

LETTER TO OUR INVESTORS

Setting a New Standard for Midstream

2019 was an outstanding year of project execution and record-setting safety performance for ONEOK. These results set the stage for strong growth at attractive returns. Our extensive asset position and exceptional financial strength allow us to perform well even in challenging times.

In 2018 and 2019, we turned our attention to construction of several significant capital-growth projects. Building an organic growth program of this scale, while maintaining safe and reliable operations of our existing assets, is challenging. It requires focus, dedication and collaboration with all stakeholders, including landowners, public officials, contractors and many others.

Thankfully, but not surprisingly, our employees rose to the challenge, completing these projects safely, on time and on budget. These critical projects are expected to significantly increase capacity and demonstrate our ability to grow alongside our customers.

For example, Williston Basin producers continue to see improvements through enhanced completion techniques, yielding increased natural gas liquids (NGL) and natural gas volumes delivered to our system.

To meet our Williston customers' needs for additional capacity, ONEOK built the Elk Creek NGL pipeline and two natural gas processing plants – Demicks Lake I and Demicks Lake II. We are also expanding the Bear Creek facility and the Elk Creek Pipeline. This new infrastructure will bring much needed support to our customers as they strive to significantly reduce the amount of natural gas flared in the region.

In addition to completing several growth projects in 2019, we also:

- Achieved outstanding environment, safety and health (ESH) performance, resulting in the company's lowest incident rates for employee injuries and preventable vehicle accidents in the past 10 years and agency reportable environmental events over the past six years.
- Increased volumes of NGL raw feed throughput and natural gas processed across our system each by 7% compared with 2018.
- Increased net income and adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) by 11% and 5%, respectively, compared with 2018.
- Announced expansions of our Bear Creek natural gas processing plant and Mid-Continent NGL fractionation facility and infrastructure; an additional 40,000 bpd expansion of our West Texas LPG pipeline; and an extension of our Bakken NGL Pipeline.
- Increased dividends paid to $3.53 per share, a 9% increase compared with 2018.
- Achieved dividend coverage of 1.38 times.
- Ended the year with a strong balance sheet and investment-grade credit ratings.

Elk Creek Pipeline Construction in Colorado

Mont Belvieu Fractionation Facility Construction in Texas

Demicks Lake I Natural Gas Processing Plant Construction in North Dakota

Our focus in 2020 remains on operating our network of assets in the manner for which ONEOK has a strong reputation – safely, reliably and in an environmentally sustainable way. The anticipated completion of additional growth projects, many in the first quarter 2020, will result in a decrease in capital spending as our strong balance sheet gets even stronger.

We expect earnings from our completed projects to drive net income and adjusted EBITDA growth of approximately 16% and 25%, respectively, in 2020 and provide support for continued growth through:

- Increased natural gas on our system as a result of new supply and reduced flaring in the Williston Basin.
- Increased NGLs from our Rocky Mountain region and Permian Basin operations to the Gulf Coast market center.
- Completion of the Arbuckle II Pipeline, MB-4 fractionator and an 80,000 bpd expansion of the West Texas LPG pipeline.

We continue to focus on our environmental, social and governance (ESG) practices, and our efforts have been rewarded. In 2019, we were the only U.S. midstream company added to the Dow Jones Sustainability North America Index. In total, we now are listed in 30 ESG-related indexes. We invite you to read our most recent Corporate Sustainability Report for more on these efforts.

Of course, our achievements over the past year are attributable to the nearly 3,000 employees across our operations. We thank them for their continued dedication to our company and to the communities where we operate and where they live and work.

In 2019, some of our operating areas experienced record-breaking floods. ONEOK and our employees responded with more than $1 million for flood relief efforts, as well as countless hours volunteered by employees. We are proud that they continue to exhibit our core values every day, and especially during the times of greatest need.

Thank you to our board of directors for its support as our company evolves to meet the needs of our stakeholders. Our focus in 2020 remains on maintaining our financial strength and safely and successfully completing our capital-growth projects, which are expected to create exceptional value for our stakeholders and investors by building on our strong asset position.

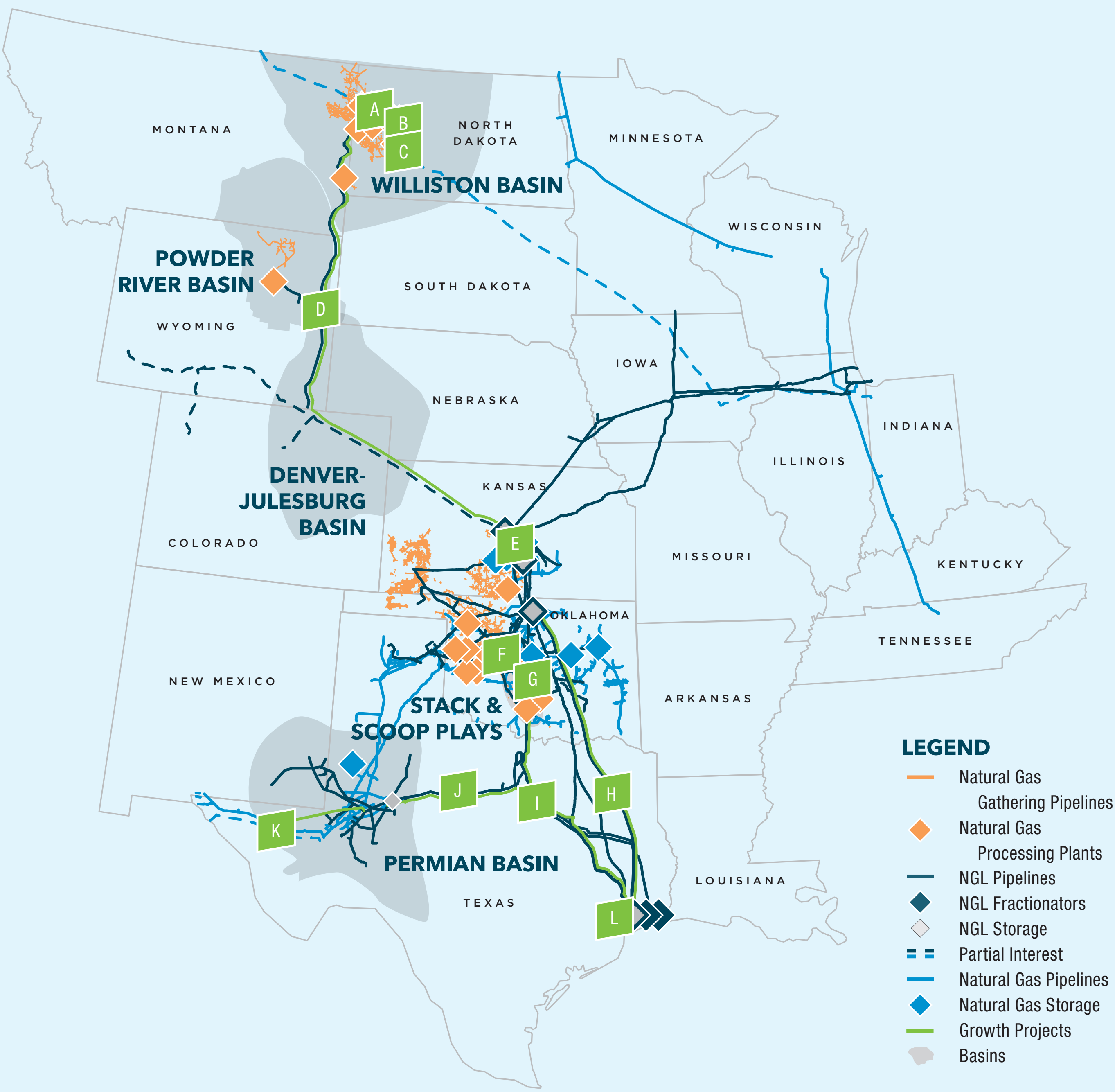
And finally, thank you to our investors for your continued trust and investment in ONEOK. You are a part of our reliability story as you continue to invest in ONEOK's future.

John W. Gibson
Chairman

March 11, 2020

Terry K. Spencer
President and Chief Executive Officer

Our Assets



GROWTH PROJECTS

- A Bakken NGL Pipeline Extension (IN PROGRESS)
- B Demicks Lake Plants I, II (COMPLETED) and III* (IN PROGRESS)
- C Bear Creek Plant Expansion (IN PROGRESS)
- D Elk Creek Pipeline (COMPLETED) and Expansion* (IN PROGRESS)
- E Mid-Continent Fractionation Facility Expansions (IN PROGRESS)
- F Canadian Valley Plant Expansion (COMPLETED)
- G ONEOK Gas Transportation Expansions (COMPLETED)
- H Sterling III Pipeline Expansion (COMPLETED)
- I Arbuckle II Pipeline (COMPLETED) and Expansion (IN PROGRESS)
- J West Texas LPG Pipeline Expansions I (COMPLETED), II, III and IV* (IN PROGRESS)
- K Roadrunner and ONEOK WesTex Expansions (COMPLETED)
- L MB-4 and MB-5 Fractionators and Storage (IN PROGRESS)

*Suspended or scope reduced on March 11, 2020.

Growth Projects Timeline

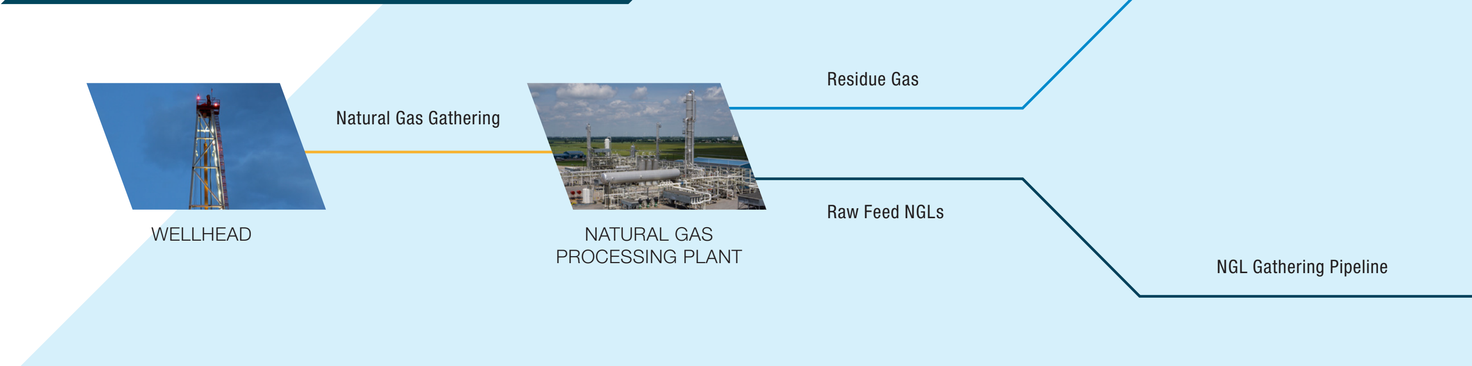
2018

- West Texas LPG Pipeline Expansion I
- Sterling III Pipeline Expansion
- Canadian Valley Plant Expansion and Infrastructure
- ONEOK Gas Transportation Westbound Expansion

2019

- ONEOK Gas Transportation Eastbound Expansion
- ONEOK WesTex Transmission Expansion
- Roadrunner Gas Transmission Bidirectional Expansion
- Demicks Lake I Plant and Infrastructure
- Elk Creek Pipeline and Infrastructure

MIDSTREAM INDUSTRY



2020

Demicks Lake II Plant and Infrastructure

Arbuckle II Pipeline and Infrastructure

MB-4 Fractionator and Infrastructure

West Texas LPG Pipeline Expansion II and Arbuckle II Connection

Bakken NGL Pipeline Extension

2021

MB-5 Fractionator and Infrastructure

Arbuckle II Pipeline Extension and Infrastructure

Arbuckle II Pipeline Expansion

West Texas LPG Pipeline Expansions III and IV*

Mid-Continent Fractionation Facility Expansions

Bear Creek Plant Expansion and Infrastructure

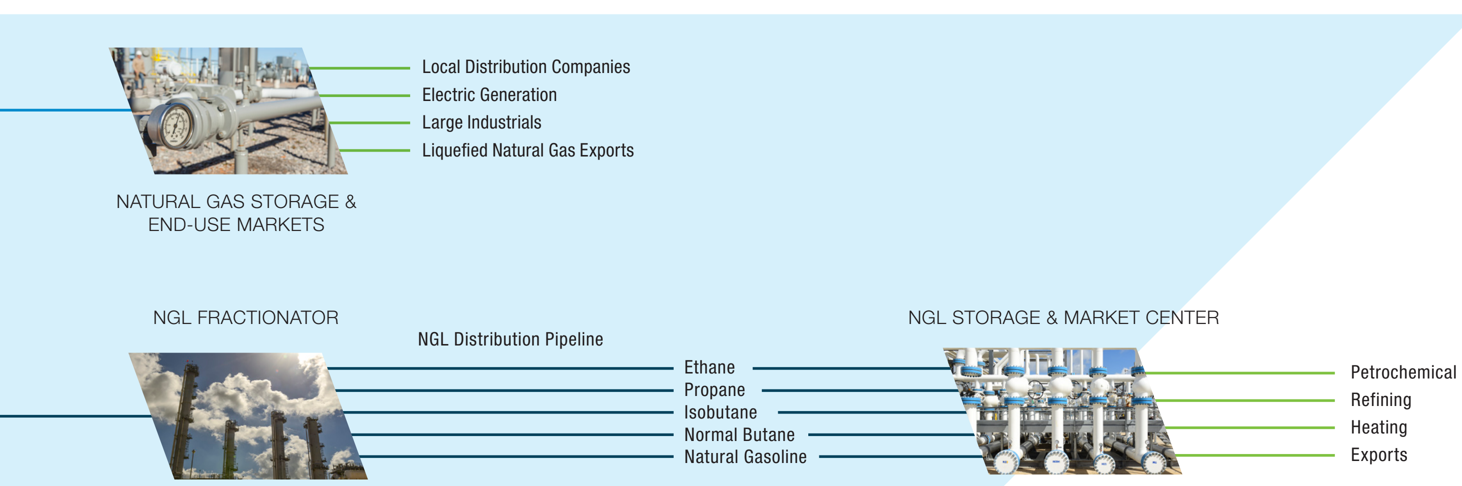
Elk Creek Pipeline Expansion*

Demicks Lake III Plant and Infrastructure*

Completed Project

Expected Completion

*Suspended or scope reduced on March 11, 2020.



Operational Highlights

As a midstream service provider, our producers rely on our nondiscretionary services to transport, process, fractionate and store NGLs and natural gas. In short, our network of assets is a critical link between the wellhead and the marketplace.

Consumers also rely on the products that move through our assets to fuel their businesses and daily activities.

That's why reliability is so important to us. From how we design our pipeline system with safety in mind; to how we plan our asset maintenance and integrity programs; to how we care for the environment; to how we adapt to meet changing regulations; to how we retain our talented workforce – reliability is a necessary part of everything we do.

It is built into every step of our operations to facilitate uninterrupted service for customers and consumers when and where they need us most.

Bushton Fractionation Facility in Kansas

Arbuckle II Pipeline Construction in Texas

Mont Belvieu Fractionation Facility Construction in Texas

Doubling the Backbone of Our NGL Business

In 2019, demand for NGL services continued to increase in some of the most productive shale plays in the country – the Williston Basin in North Dakota, the Powder River Basin in Wyoming, the Denver-Julesburg Basin in Colorado, the STACK and SCOOP areas in the Mid-Continent and the Permian Basin in West Texas.

ONEOK is uniquely positioned in the heart of these basins and has made significant investments in organic capital-growth projects to provide additional takeaway capacity to meet producer needs in the short- and long-term.

The Elk Creek Pipeline, completed in late 2019, provides key NGL raw feed takeaway from the Williston and Powder River basins to the Conway, Kansas, market center.

The Arbuckle II Pipeline, which was completed in the first quarter 2020, moves supply growth from the basins we serve to the Mont Belvieu, Texas, market center. Through low cost, high return expansions, the pipeline is expandable up to 1 million bpd of capacity with additional pump stations.

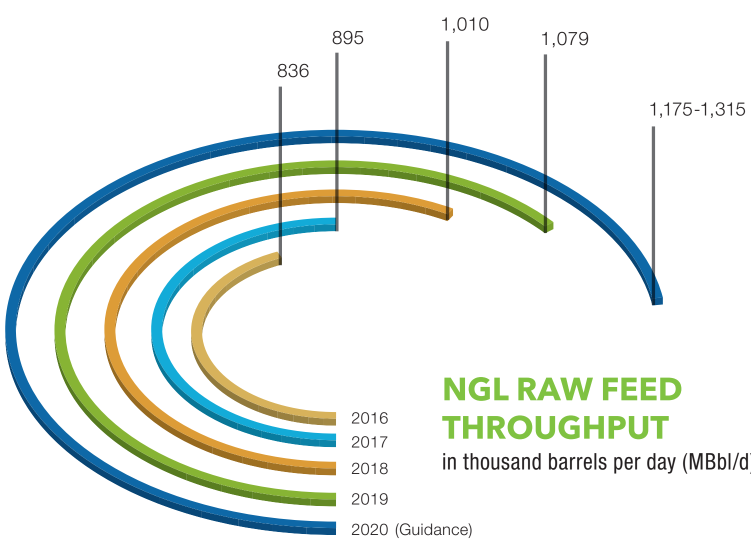
In the Permian Basin, we continue to execute on our long-term contracting strategy. We have announced three expansions to our West Texas LPG pipeline system, totaling an estimated 160,000 bpd of additional capacity, since ONEOK's acquisition of it in 2014.

Upon completion, all of our announced NGL pipeline growth projects are expected to more than double systemwide NGL gathering capacity compared with 2018.

In addition to our long-haul pipeline projects, we also are in the midst of adding two 125,000 bpd fractionators at our Mont Belvieu facilities: the MB-4 fractionator, which is nearing full completion, and our MB-5 fractionator, which is scheduled to be completed in the first quarter 2021.

We also announced expansions at our Mid-Continent NGL fractionation facilities totaling an estimated 65,000 bpd.

Once these projects are completed by the end of the first quarter 2021, ONEOK expects to operate more than 1.1 million bpd of total fractionation capacity at the Conway and Mont Belvieu NGL market centers. This represents more than a 35% increase in fractionation capacity compared with 2018.



NGL RAW FEED THROUGHPUT
in thousand barrels per day (MBbl/d)

Expanding Our Reliable Natural Gas Services

Providing reliable natural gas services in many of the same basins where we gather NGLs continues to be a key part of ONEOK's strategy. Gathering, processing and transporting natural gas is essential to the many customers we serve as their production continues to grow.

In 2019, ONEOK added more than 640 new well connections from which we gather natural gas. Approximately 525 of total wells connected in 2019 were in the Rocky Mountain region, where ONEOK has more than 3 million acres dedicated to our system in the Williston Basin and approximately 130,000 acres dedicated in the Powder River Basin.

To meet the growing demand for natural gas processing capacity to extract NGLs, we completed construction in 2019 and early 2020 on our eighth and ninth natural gas processing plants in the region: the 200 MMcf/d Demicks Lake I and the 200 MMcf/d Demicks Lake II.

And we announced a 200 MMcf/d expansion of our Bear Creek facility to add much needed processing capacity in a geographically isolated area of the basin.

Once completed, these facilities are expected to bring our total natural gas processing capacity to approximately 1.7 billion cubic feet per day (Bcf/d) in the Williston Basin by the end of the first quarter 2021.

In the Mid-Continent, which includes the STACK and SCOOP areas in Oklahoma, ONEOK connected approximately 120 new wells in 2019 and operates approximately 1.0 Bcf/d of natural gas processing capacity.

By the first quarter 2021, we expect to operate nearly 2.7 Bcf/d of natural gas processing capacity systemwide.

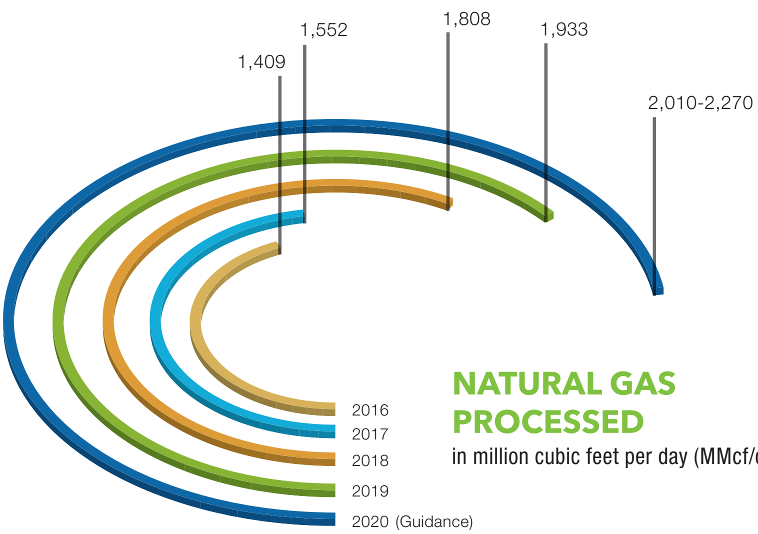
ONEOK also completed approximately 1.5 Bcf/d of natural gas transportation infrastructure expansions across our system in late 2018 and early 2019. These projects, located in the Permian Basin and Mid-Continent region, are backed by multiple firm transportation commitments and provide much needed residue takeaway for customers.

These expansions on existing infrastructure in our natural gas and NGL businesses are central to our long-term growth strategy.

Canadian Valley Natural Gas Processing Plant in Oklahoma


Rock Creek Compressor Station in Oklahoma

NATURAL GAS PROCESSED
in million cubic feet per day (MMcf/d)




Bear Creek Natural Gas Processing Plant in North Dakota

Employee Volunteering for United Way

Environmental Surveys in North Dakota

Standard of Sustainability

Critical to our reliability efforts, environmental, social and governance (ESG) is multifaceted and helps reduce risks to allow for consistent operations while pursuing new opportunities – all to meet the needs of our stakeholders.

ONEOK has a dedicated Sustainability team that furthers sustainable business practices and awareness, and identifies industry opportunities and challenges. An internal ESG Council, composed of leaders from all areas of the company, identifies and recommends opportunities for improving our sustainability performance and reporting.

Additional information about our companywide efforts is available online at ONEOK.com/Sustainability.

RECOGNITIONS

In 2019, we are proud to have earned the following ESG-related recognitions:

- Added to the Dow Jones Sustainability North America Index.
- Inclusion in the FTSE4Good and MSCI USA ESG-related indexes.
- First in industry in Just Capital’s JUST ETF.
- Platinum Verification in Sustainable Tulsa’s Scorecard program.
- M.e.t. Green Business of the Year.
- GPA Midstream Energy Conservation Award.
- Oklahoma Veteran Employee Champion.
- Scored 95/100 on Human Rights Campaign Foundation’s Corporate Equality Index.
- Henry Bellmon Sustainability Award.

ONEOK Financial Highlights

Years ended Dec. 31		2019		2018		2017
Consolidated financial information (millions of dollars)						
Operating income	$	1,914.4	$	1,835.5	$	1,391.8
Net income[1]	$	1,278.6	$	1,155.0	$	593.5
Net income attributable to ONEOK, Inc.[1]	$	1,278.6	$	1,151.7	$	387.8
Total assets	$	21,812.1	$	18,231.7	$	16,845.9
Common stock data						
Shares outstanding at Dec. 31		413,239,050		411,532,606		388,703,543
Data per common share						
Diluted earnings per share from net income available to common shareholders[1]	$	3.07	$	2.78	$	1.29
Dividends paid per share	$	3.53	$	3.245	$	2.72
Market price range						
High	$	76.50	$	71.40	$	58.83
Low	$	54.28	$	50.79	$	47.41
Year-end	$	75.67	$	53.95	$	53.45

[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 ONEOK'S NET INCOME TO ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW – UNAUDITED (MILLIONS OF DOLLARS)

		2019		2018		2017
Net income	$	1,278.6	$	1,155.0	$	593.5
Interest expense, net of capitalized interest		491.8		469.6		485.7
Depreciation and amortization		476.5		428.6		406.3
Income tax expense		372.4		362.9		447.3
Impairment charges		–		–		20.2
Noncash compensation expense		26.7		38.0		13.4
Equity AFUDC and other noncash items[2]		(65.8)		(6.6)		20.5
Adjusted EBITDA[3]		2,580.2		2,447.5		1,986.9
Interest expense, net of capitalized interest		(491.8)		(469.6)		(485.7)
Maintenance capital		(195.6)		(188.4)		(147.2)
Equity in net earnings from investments, excluding noncash impairment charges		(154.5)		(158.4)		(159.3)
Distributions received from unconsolidated affiliates		257.6		197.3		196.1
Other		20.2		(6.0)		(6.1)
Distributable cash flow[3]	$	2,016.1	$	1,822.4	$	1,384.7
Dividends paid to preferred shareholders		(1.1)		(1.1)		(0.6)
Distributions paid to public limited partners		–		–		(271.0)
Distributable cash flow to shareholders	$	2,015.0	$	1,821.3	$	1,113.1
Dividends paid	$	(1,456.5)	$	(1,334.0)	$	(828.1)
Distributable cash flow in excess of dividends paid	$	558.5	$	487.3	$	285.0
Dividends paid per share	$	3.530	$	3.245	$	2.720
Dividend coverage ratio[3]		1.38		1.37		1.34

[2] 2017 includes our contribution to the ONEOK Foundation of 20,000 shares of Series E Preferred Stock, with an aggregate value of $20.0 million.

[3] 2017 includes transaction-related pretax cash costs of $30 million, or 0.04 times dividend coverage, associated with the ONEOK and ONEOK Partners merger transaction.

NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURES

ONEOK has disclosed in this annual report adjusted EBITDA, distributable cash flow and dividend coverage ratio, 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 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.
- 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.
- Dividend coverage ratio is defined as ONEOK's distributable cash flow to ONEOK shareholders divided by the dividends paid for the period.

These non-GAAP financial measures described above are useful to investors because they, and 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 ONEOK's financial performance and to compare ONEOK's financial performance with the performance of other companies within ONEOK's industry. Adjusted EBITDA, distributable cash flow and dividend coverage ratio 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, distributable cash flow and dividend coverage ratio are included in the tables.

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 capital-growth projects and other future operations (including plans to construct additional natural gas and NGL pipelines and processing and fractionation 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," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "might," "plan," "outlook," "potential," "project," "scheduled," "should," "will," 'would" 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 impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to drill and obtain necessary permits; regulatory compliance; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- 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;
- 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;
- demand for our services and products in the proximity of our facilities;
- 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 United States natural gas and crude oil; and
  - availability of additional storage capacity;
- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers', customers' or shippers' facilities;
- 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;
- economic climate and growth in the geographic areas in which we do business;
- the timing and extent of changes in energy commodity prices;
- 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 profitability of assets or businesses acquired or constructed by us;
- the risk of a slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- 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;
- 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 uncontracted capacity in our assets being greater or less than expected;
- 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;
- our ability to control construction costs and completion schedules of our pipelines and other projects;
- 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 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 results of administrative proceedings and litigation, regulatory actions, executive orders, 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 the CFTC;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- the capital-intensive nature of our businesses;
- the mechanical integrity of facilities operated;
- 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 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 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;
- our ability to access capital at competitive rates or on terms acceptable to us;
- the impact and outcome of pending and future litigation;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- our ability to control operating costs and make cost-saving changes;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- the risk inherent in the use of information systems in our respective businesses and those of our counterparties and service providers, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- the impact of potential impairment charges; 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 affect adversely 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.

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2019.
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:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ 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 ☒.

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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 ☒ 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 ☒.

Aggregate market value of registrant's common stock held by non-affiliates based on the closing trade price on June 28, 2019, was $28.1 billion.

On February 18, 2020, the Company had 413,319,000 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 20, 2020, are incorporated by reference in Part III.

ONEOK, Inc.
2019 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:

$1.5 Billion Term Loan Agreement	The senior unsecured delayed-draw three-year $1.5 billion term loan agreement dated November 19, 2018
$2.5 Billion Credit Agreement	ONEOK's $2.5 billion revolving credit agreement, as amended
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2019
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
Btu	British thermal unit
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
DJ	Denver-Julesburg
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.
KCC	Kansas Corporation Commission
LIBOR	London Interbank Offered Rate
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
MMBbl/d	Million barrels per day
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
Northern Border Pipeline	Northern Border Pipeline Company, a 50% owned joint venture
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ONEOK	ONEOK, Inc.
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners Term Loan Agreement	The senior unsecured three-year $1.0 billion term loan agreement dated January 8, 2016, as amended

OPIS	Oil Price Information Service
Overland Pass Pipeline	Overland Pass Pipeline Company, LLC, a 50% owned joint venture
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% 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
Topic 606	Accounting Standards Update 2014-09, "Revenue from Contracts with Customers"
West Texas LPG	West Texas LPG pipeline and Mesquite pipeline
WTI	West Texas Intermediate
WTLPG	West Texas LPG Pipeline Limited Partnership
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," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "might," "outlook," "plan," "potential," "project," "scheduled," "should," "will," "would" 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.

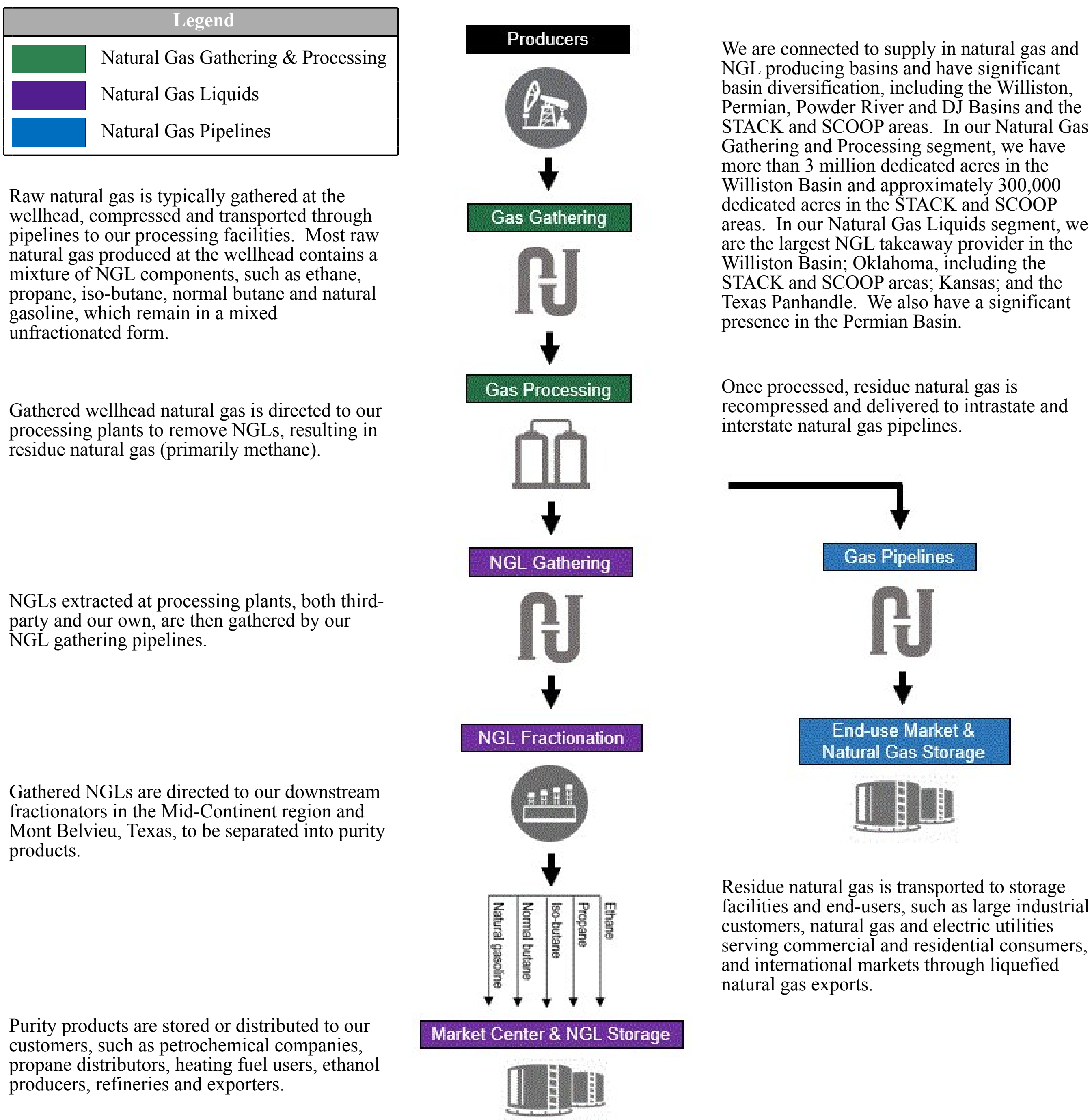
PART I

ITEM 1. BUSINESS

GENERAL

We are 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 NGL systems, connecting NGL supply in the Rocky Mountain, Permian and Mid-Continent 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.

Midstream Value Chain



EXECUTIVE SUMMARY

Business Update and Market Conditions - We operate primarily fee-based businesses in each of our three reportable segments, and our consolidated earnings were approximately 90% fee-based in 2019. Volumes increased across our system in our Natural Gas Gathering and Processing and Natural Gas Liquids segments in 2019, compared with 2018, as a result of our completed capital-growth projects, continued drilling and producer improvements in production due to enhanced completion techniques, offset partially by natural production declines. Since the beginning of 2018, we have completed several capital-growth projects that include NGL pipelines, NGL fractionators, natural gas processing plants and related natural gas and NGL infrastructure, and expect capital expenditures to decrease in 2020 and 2021, compared with 2019. Our NGL projects in the Gulf Coast allow flexibility to add NGL fractionators, NGL storage and, potentially, new export facilities in the future. We expect these projects to meet the needs of producers, natural gas processors and the petrochemical industry that require additional midstream infrastructure to accommodate increasing supply and demand.

We experienced fluctuating NGL location price differentials due to increased supply, increased demand in the Mid-Continent region, infrastructure constraints and slower demand growth in the Gulf Coast due primarily to delays in the startup of petrochemical facilities and constrained NGL export facilities. The Conway-to-Mont Belvieu OPIS price differential for ethane in ethane/propane mix averaged $0.07 per gallon in 2019, compared with $0.15 per gallon in 2018, which resulted in lower earnings from our optimization and marketing activities in our Natural Gas Liquids segment. We expect narrower NGL location price differentials in 2020.

Rocky Mountain Region - We expect to benefit from increased production in this region, which includes the Williston, Powder River and DJ Basins. In our Natural Gas Gathering and Processing segment, gathered and processed volumes increased in 2019, compared with 2018, due primarily to our capital-growth projects, new well connections and increased producer productivity. Our Demicks Lake I natural gas processing plant was placed in service in October 2019, and we expect it to reach its 200 MMcf/d capacity in the first quarter 2020 due to natural gas flaring by producers on our more than 3 million dedicated acres in the Williston Basin. In addition, we completed construction of our Demicks Lake II natural gas processing plant in January 2020. With continued volume growth expected, we are in the process of expanding our Bear Creek plant by 200 MMcf/d, which is expected to be completed in first quarter 2021, and recently announced plans to construct our Demicks Lake III natural gas processing plant, with capacity of 200 MMcf/d and expected completion in the third quarter 2021. Upon completion of these projects, our total processing capacity will be approximately 1.9 Bcf/d in the Williston Basin and is expected to help producers meet North Dakota's natural gas capture targets and add incremental NGLs to our NGL gathering system.

In our Natural Gas Liquids segment, we announced the completion of our Elk Creek pipeline in December 2019. We are the largest NGL takeaway provider and expect our NGL pipelines to transport more than 240 MBbl/d of NGLs out of this region by the end of the first quarter 2020 due to a combination of growth in volumes from our new and existing processing plants, third-party processing plants and volumes previously transported by rail. In addition, we recently announced an expansion of our Elk Creek pipeline to 400 MBbl/d by adding additional pump stations. The project is expected to be fully completed in the third quarter 2021, with a portion of this incremental capacity available as early as first quarter 2021. In April 2019, we announced a project to extend our Bakken NGL pipeline into an area of the Williston Basin with limited access to NGL pipeline takeaway capacity. This project will provide connectivity for third-party processing plants to key NGL market centers as well as provide additional volumes to our Elk Creek pipeline. To accommodate expected volumes, we are also expanding our Mid-Continent NGL fractionation facilities by 65 MBbl/d and constructing an extension of our Arbuckle II pipeline farther north.

Mid-Continent Region - In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the STACK and SCOOP areas where volumes continued to increase in 2019, compared with 2018. We expect continued demand for our services from producers that need takeaway capacity for natural gas and NGLs out of this region. In our Natural Gas Gathering and Processing segment, natural gas gathered and processed volumes increased in this region in 2019, compared with 2018, due primarily to new well connections. We expect volumes in this region to decline modestly in 2020, compared with 2019.

Our Natural Gas Pipelines segment transports natural gas from more than 35 natural gas processing plants in Oklahoma. We completed pipeline expansions to provide increased westbound transportation services from the STACK area to multiple interstate pipeline delivery points in western Oklahoma and a 150 MMcf/d eastbound expansion from the STACK and SCOOP areas to an eastern Oklahoma interstate pipeline delivery point.

Permian Basin - We expect our Natural Gas Liquids and Natural Gas Pipelines business segments to continue to benefit from increased production in the Permian Basin from the highly productive Delaware and Midland Basins. In our Natural Gas Liquids segment, we are well-positioned in the Permian Basin through our West Texas LPG pipeline system. Due to our expansion of the system in the third quarter 2018 and new plant connections, volumes increased in 2019, compared with 2018. We expect volumes to continue to increase on our West Texas LPG pipeline system as our previously announced second and third expansions are completed, which will increase the mainline capacity out of the Permian Basin by 80 MBbl/d in the first quarter 2020 and 40 MBbl/d in the first quarter 2021, respectively, as well as connect our West Texas LPG pipeline with our Arbuckle II pipeline in north Texas. In addition, we recently announced the fourth expansion of our West Texas LPG pipeline system by 100 MBbl/d, which is expected to be completed in the second quarter 2021. These projects are expected to position our West Texas LPG pipeline system for significant NGL volume growth and are backed by long-term acreage and/or plant dedications.

In our Natural Gas Pipelines segment, our Roadrunner joint venture and our WesTex pipeline are well-positioned to serve growth in the Permian Basin. 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 to Mexico and transport natural gas to other markets in the region.

Gulf Coast - Demand for NGLs is expected to increase at the Mont Belvieu, Texas, NGL market center as new world-scale ethylene production projects, petrochemical plant expansions and NGL export facilities continue to be completed. We are constructing our Arbuckle II pipeline to support expected supply growth and transport NGLs to the Gulf Coast market center and have announced an expansion of our Arbuckle II pipeline to a total capacity of 500 MBbl/d. NGL supply growth and other new NGL pipelines recently completed or being constructed, including our Elk Creek and West Texas LPG pipeline projects, are increasing NGL deliveries to Mont Belvieu, Texas. While we have significant NGL fractionation and storage assets in this area, additional capacity is needed to accommodate expected volume growth. To respond to this need, we are constructing two additional 125 MBbl/d fractionators with related infrastructure in Mont Belvieu, Texas, MB-4 and MB-5, which are both fully contracted. In December 2019, we completed construction of 75 MBbl/d of the MB-4 capacity, with the remaining 50 MBbl/d to be completed in the first quarter 2020, and MB-5 is expected to be completed in the first quarter 2021. Following the completion of MB-4 and MB-5, we expect our NGL fractionation capacity to be approximately 600 MBbl/d in the Gulf Coast and more than 1 MMBbl/d across our entire system. Our MB-5 project also includes system expansions that provide infrastructure capacity to support additional assets as we continue to evaluate opportunities for fractionation, storage and, potentially, export facilities to meet the supply and demand for NGLs.

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report 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:

- Operate in a safe, reliable, environmentally responsible and sustainable manner - environmental, safety and health continues 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. In 2019, we were added to the Dow Jones Sustainability North America Index, which recognizes companies for industry-leading environmental, social and governance performance;
- Pursue organic investments in our existing operating regions to support earnings growth - we expect our investment in capital projects to create stable earnings growth that positions us to grow our dividend. In 2019, we paid dividends of $3.53 per share, an increase of 9% compared with the prior year. Our dividend increase and expected future dividend growth is due primarily to earnings growth from capital projects;
- Manage our balance sheet and maintain investment-grade credit ratings - we seek to maintain investment-grade credit ratings, fund capital-growth projects and begin to pay down debt. We expect to benefit from increasing cash flows from operations in 2020, which we expect to reduce leverage and fund capital-growth projects. At December 31, 2019, we had no borrowings outstanding under our $2.5 Billion Credit Agreement, $220 million of commercial paper outstanding and $21 million of cash and cash equivalents; and
- Attract, select, develop, motivate, challenge and retain a diverse group of employees to support strategy execution - 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.

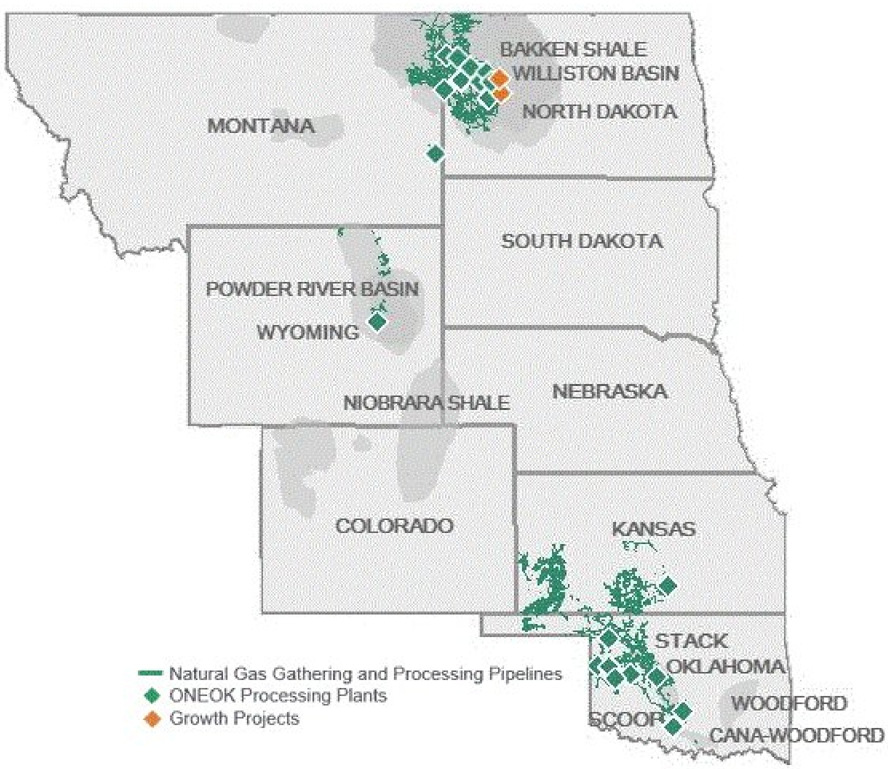
Natural Gas Gathering and Processing

Overview - Our Natural Gas Gathering and Processing segment provides midstream services to producers in North Dakota, Montana, Wyoming, Kansas and Oklahoma.

Rocky Mountain region - The Williston Basin is located in portions of North Dakota and Montana and includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations, and is an active drilling region. Our completed capital-growth projects in the Williston Basin have increased our gathering and processing capacity 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 eastern 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.



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

- 18,900 miles of natural gas gathering pipelines;
- ten natural gas processing plants with 1.0 Bcf/d of processing capacity in the Mid-Continent region, and 12 natural gas processing plants with 1.5 Bcf/d of processing capacity in the Rocky Mountain region; and
- 14 MBbl/d of NGL fractionation capacity at various natural gas processing plants.

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.

We are in the process of expanding our Bear Creek plant by 200 MMcf/d and recently announced plans to construct our Demicks Lake III natural gas processing plant, with capacity of 200 MMcf/d, in the core of the Williston Basin. The additional capacity from these projects is excluded from the assets listed above.

See "Recent Developments" in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report for more information on our growth projects.

Sources of Earnings - Earnings for this segment are derived primarily from the following types of service contracts:

- POP with fee contracts with no producer take-in-kind rights - We purchase raw natural gas and charge contractual fees for providing midstream services, which include gathering, treating, compressing and processing the producer's natural gas. After performing these services, we sell the commodities and remit a portion of the commodity sales proceeds to the producer less our contractual fees. This type of contract represented 63% and 60% of supply volumes in this segment for 2019 and 2018, respectively.
- POP with fee contracts with producer take-in-kind rights - We purchase a portion of the raw natural gas stream, charge fees for providing the midstream services listed above, return primarily the residue natural gas to the producer, sell the remaining commodities and remit a portion of the commodity sales proceeds to the producer less our contractual fees. This type of contract represented 33% and 36% of supply volumes in this segment for 2019 and 2018, respectively.
- Fee-only - Under this type of contract, we charge a fee for the midstream services we provide, based on volumes gathered, processed, treated and/or compressed. Our fee-only contracts represented 4% of supply volumes in this segment in 2019 and 2018.

For commodity sales, 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 primarily to our affiliate in the Natural Gas Liquids segment.

Utilization - The utilization rates for our natural gas processing plants were 84% and 83% for 2019 and 2018, 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% ownership interest in Bighorn Gas Gathering, which gathers dry natural gas produced in the Powder River Basin;
- 42.6% ownership interest in Fort Union Gas Gathering, which gathers dry natural gas produced in the Powder River Basin and delivers it to the interstate pipeline system;
- 35% 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
- 10.2% ownership interest in Venice Energy Services Co., a natural gas processing facility near Venice, Louisiana.

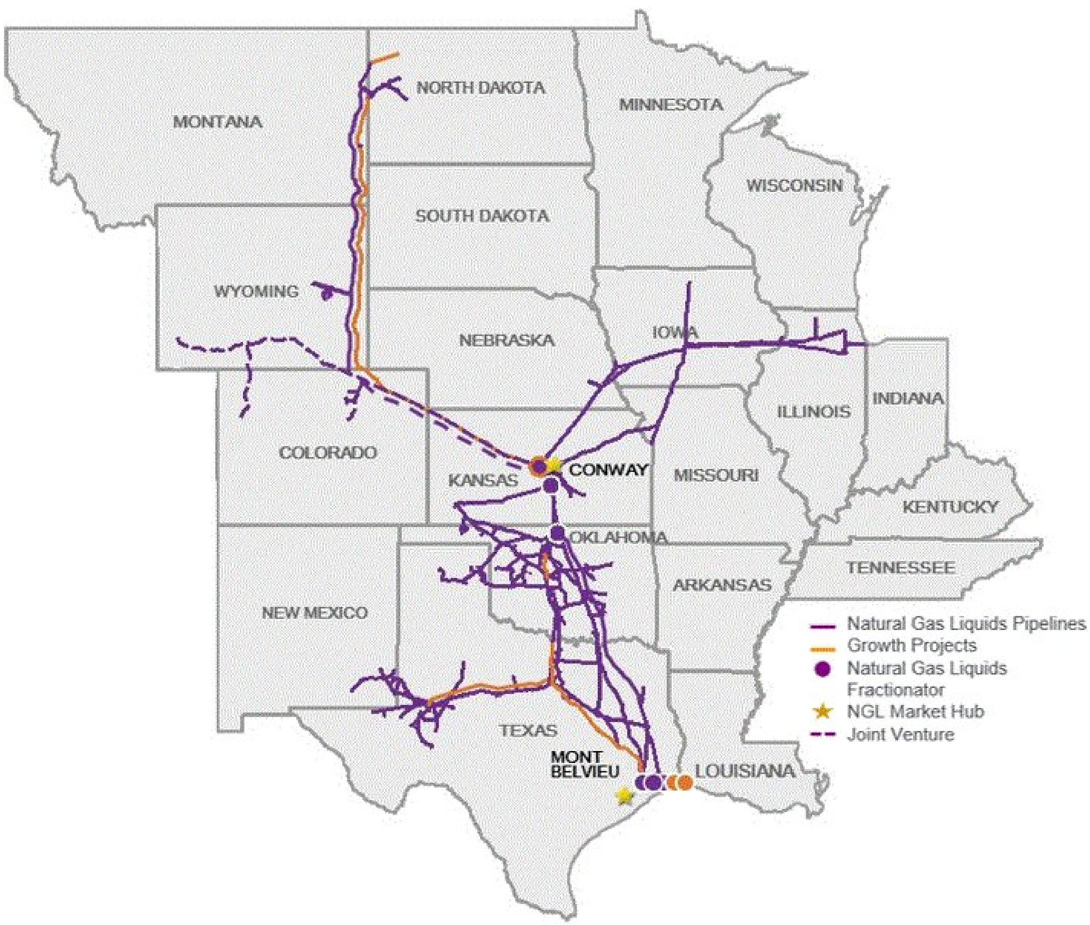
See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of our unconsolidated affiliates.

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, Powder River and DJ Basins. 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 NGL 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. The majority of the pipeline-connected natural gas processing plants in the Williston Basin, Oklahoma, Kansas and the Texas Panhandle are connected to our NGL gathering systems. We own and operate truck- and rail-loading and -unloading facilities connected to our NGL fractionation and pipeline assets. We also own FERC-regulated NGL distribution pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. A portion of our ONEOK North System transports refined petroleum products, including unleaded gasoline and diesel, from Kansas to Iowa.



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

- 8,380 miles of gathering pipelines with peak capacity of 1,820 MBbl/d, including 5,550 miles of FERC-regulated pipelines with peak capacity of 920 MBbl/d;
- 4,490 miles of distribution pipelines with peak capacity of 1,400 MBbl/d, including 4,460 miles of FERC-regulated pipelines with peak capacity of 1,360 MBbl/d;
- eight NGL fractionators with combined operating capacity of 870 MBbl/d (includes interests in our proportional share of operating capacity), including 520 MBbl/d in the Mid-Continent region and 350 MBbl/d in the Gulf Coast region;
- one isomerization unit with operating capacity of 10 MBbl/d;
- one ethane/propane splitter with operating capacity of 40 MBbl/d;
- six NGL storage facilities with operating storage capacity of 20 MMBbl; and
- eight NGL product terminals.

In addition, we lease 10 MMBbl of annual pipeline capacity near our ONEOK North System and have access to 5 MMBbl of combined NGL storage capacity at facilities in Kansas and Texas and 60 MBbl/d of NGL fractionation capacity in the Gulf Coast through service agreements.

Our uncompleted growth projects are excluded from the assets listed above and include:

- gathering pipelines, including expansions, with combined operating capacity of 880 MBbl/d;
- the MB-5 fractionator in the Gulf Coast with operating capacity of 125 MBbl/d;
- remaining fractionation capacity on the MB-4 fractionator in the Gulf Coast of 50 MBbl/d; and
- additional fractionation capacity in the Mid-Continent of 65 MBbl/d.

See "Recent Developments" in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report for more information on our growth projects.

Sources of Earnings - Earnings 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 business activities are categorized as follows:

- Exchange services - We utilize our assets to gather, transport, treat and fractionate unfractionated NGLs, thereby converting them into marketable NGL products delivered 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 NGL 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. To the extent we hold unfractionated NGLs in inventory, the related contractual fees will not be recognized until the unfractionated inventory is fractionated and sold.

Utilization - The utilization rates for our various assets, including leased assets, have been impacted by ethane rejection. The utilization rates for 2019 and 2018, respectively, were as follows:

- our NGL gathering pipelines were 78% in both years;
- our NGL distribution pipelines were 63% and 59%; and
- our NGL fractionators were 84% and 85%.

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% ownership interest in Overland Pass Pipeline Company, which operates an interstate NGL pipeline system extending 760 miles, originating in Wyoming and Colorado and terminating in Kansas;
- 50% ownership interest in Chisholm Pipeline Company, which operates an interstate NGL pipeline system extending 185 miles from origin points in Oklahoma and terminating in Kansas; and
- 50% 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 M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Government Regulation - The operations and revenues of our NGL pipelines are regulated by various state and federal government agencies. Our interstate NGL 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 NGL pipelines that provide common carrier service are subject to the jurisdiction of the OCC, KCC and RRC, respectively.

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

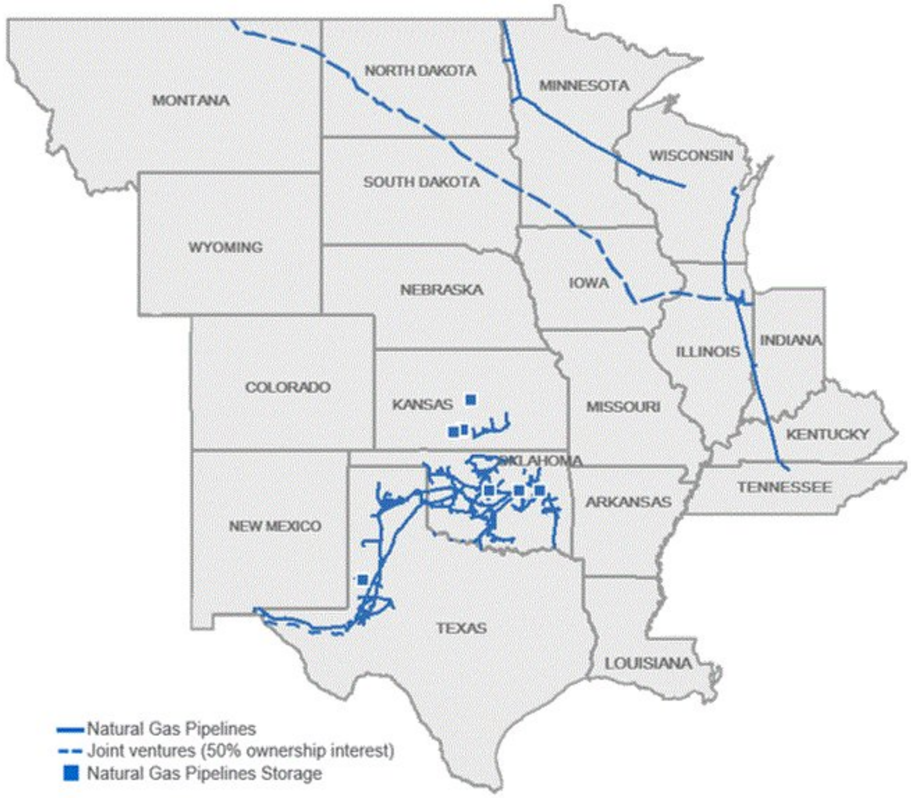
Natural Gas Pipelines

Overview - Our Natural Gas Pipelines segment provides transportation and storage services to end users through its wholly owned assets and its 50% 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. 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 and Midland Basins in the Permian Basin. These pipelines are capable of transporting natural gas throughout the western portion of Texas, including the Waha area 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.



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

- 1,500 miles of FERC-regulated interstate natural gas pipelines with 3.5 Bcf/d of peak transportation capacity;
- 5,100 miles of state-regulated intrastate transmission pipelines with peak transportation capacity of 4.3 Bcf/d; and
- six underground natural gas storage facilities with 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.

Sources of Earnings - Earnings in this segment are derived primarily from transportation and storage services.

Our transportation earnings 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 earnings 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 storage 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.

Utilization - Our natural gas pipelines were 98% and 96% subscribed in 2019 and 2018, respectively, and our natural gas storage facilities were 64% subscribed in both 2019 and 2018.

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

- 50% ownership 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% ownership interest in Roadrunner, a bidirectional pipeline, which has the capacity to transport 570 MMcf/d of natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas, and has capacity to transport approximately 1.0 Bcf/d of natural gas from the Delaware Basin to the Waha area. We are the operator of Roadrunner.

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

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.

<u>Market Conditions and Seasonality</u>

We operate primarily fee-based businesses in each of our three reportable segments, and our consolidated earnings were approximately 90% fee-based in 2019. 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. We are exposed to volumetric risk from declining well productivity, reduced drilling activity, severe weather disruptions, operational outages and ethane rejection.

Supply and Demand - Supply for each of our segments depends on crude oil and natural gas drilling and production activities, which are driven by the strength of the economy; the decline rate of existing production; producer access to capital; producer firm commitments to transportation pipelines; natural gas, crude oil and NGL prices; or the demand for each of these products from end users.

Demand for gathering and processing services is dependent on natural gas production by producers in the regions in which we operate. State 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. 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, transportation and fractionation services. Natural gas and NGL products are affected by economic conditions and the demand associated with the various industries that utilize the commodities, 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 also used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fibers. Propane is also used to heat homes and businesses. Demand for NGLs is expected to increase at the Mont Belvieu, Texas, NGL market center as new world-scale ethylene production projects, petrochemical plant expansions and NGL export facilities continue to be completed.

Commodity Prices - Our earnings are primarily fee-based in all three of our segments, with limited commodity price risk. 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. In our Natural Gas Liquids segment, we are exposed to commodity price 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, our exchange services, transportation and storage services, and optimization and marketing financial results. 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. In our Natural Gas Pipelines segment, we are exposed to commodity price risk associated with (i) changes in the price of natural gas, which impact our fuel costs and retained fuel in-kind received for our services; and (ii) the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market, which affects our natural gas storage revenue.

See additional 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, in this Annual Report.

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 generation for residential and commercial cooling, as well as agriculture-related equipment like irrigation pumps and crop dryers. 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, are also subject to some variability during seasonal periods when certain government restrictions on motor fuel blending products change. During periods of peak demand for a certain commodity, prices for that product typically increase.

Extreme weather conditions, seasonal temperature changes and the impact of temperature and humidity on the mechanical abilities of the processing equipment impact the volumes of natural gas gathered and processed and NGL volumes gathered, transported and fractionated. Power interruptions and 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, may cause a temporary interruption in the flow of natural gas and NGLs.

In our Natural Gas Pipelines segment, natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric-generation users.

Competition - We compete for natural gas and NGL supply with other midstream companies and major integrated oil companies and independent exploration and production companies that have gathering and processing assets, fractionators, intrastate and interstate pipelines and storage facilities. The factors that typically affect our ability to compete for natural gas and NGL supply are:

- quality of services provided;
- producer drilling activity;
- proceeds remitted and/or fees charged under our contracts;
- proximity of our assets to natural gas and NGL supply areas and markets;
- location of our assets relative to those of our competitors;
- efficiency and reliability of our operations;
- receipt and delivery capabilities for natural gas and NGLs that exist in each pipeline system, plant, fractionator and storage location;
- the petrochemical industry’s level of capacity utilization and feedstock requirements;
- current and forward natural gas and NGL prices; and
- cost of and access to capital.

We have responded by making capital investments to access and connect new supplies with end-user demand; increasing gathering, processing, fractionation and pipeline capacity; increasing storage, withdrawal and injection capabilities; and reducing operating costs so that we compete effectively. Our competitors also continue to invest in midstream infrastructure to address the growing natural gas and NGL supply and market demand. Our and our competitors’ infrastructure projects may affect commodity prices and compete with and could displace supply volumes from the Mid-Continent and Rocky Mountain regions and the Permian Basin where our assets are located. We believe our assets are located strategically, connecting diverse supply areas to market centers.

Customers - Our Natural Gas Gathering and Processing and Natural Gas Liquids segments derive services revenue from major and independent crude oil and natural gas producers. Our Natural Gas Liquids segment’s customers also include NGL and natural gas gathering and processing companies. Our downstream commodity sales customers are primarily utilities, large industrial companies, natural gasoline distributors, propane distributors, municipalities and petrochemical, refining and marketing companies. Our Natural Gas Pipeline segment's assets primarily serve local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, producers, processors 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, in this Annual Report.

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 517,000 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 a variety of 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 adversely 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.

Some scientists have determined that GHG emissions endanger public health and the environment because emissions of such gases may contribute to warming of the earth's atmosphere and other climatic changes. 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 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 NGL 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. In addition, many of our compressor station facilities are designed and operated with electric-driven compression units, which reduce the potential emission from these facilities, including GHG emissions.

We participate in the EPA's Natural Gas STAR Program to reduce voluntarily methane emissions. We continue to focus on maintaining low methane gas release rates 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, to purchase allowances for such emissions or to be subject to a carbon emissions tax. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations, when they will become effective or the impact on our results of operations. 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.

In 2015, PHMSA issued notices of proposed rule-making for hazardous liquid pipeline safety regulations, natural gas transmission and gathering lines and underground natural gas storage facilities, known as “the Mega Rule.” Due to the large number of rules being considered, PHMSA partitioned the new rulemaking into three sections. To date, the first section of rules was finalized and published in 2019 in the federal register. These final rules mostly address congressional mandates due to former pipeline safety reauthorizations. Coupled together, these new rules provide increased requirements for operating and maintenance, integrity management, public awareness and civil/criminal penalties. The potential capital and operating expenditures related to the new regulations are not fully known, but we do not anticipate a material impact to our planned capital or operations and maintenance costs resulting from compliance with the new or pending regulations. In 2019, legislation was introduced to reauthorize PHMSA through 2024. If passed, requirements for operations and maintenance, integrity management, public awareness, civil and criminal penalties could be increased. 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 or 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 2018 total emissions reported pursuant to EPA requirements were approximately 60 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 material costs, fees or expenses on any of these emissions.

We 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 record-keeping 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, including possible physical security enhancements. We do not expect the cost of the Site Security Plans 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, 2020, we employed 2,882 people.

INFORMATION ABOUT OUR 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	67	2011 to present	Chairman of the Board, ONEOK
Chairman of the Board		2007 to 2017	Chairman of the Board, ONEOK Partners
Terry K. Spencer	60	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
Robert F. Martinovich	62	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
Walter S. Hulse III	56	2019 to present	Chief Financial Officer, Treasurer and Executive Vice President, Strategic Planning and Corporate Affairs, ONEOK
Chief Financial Officer, Treasurer and Executive Vice President, Strategic Planning and Corporate Affairs		2017 to 2019	Chief Financial Officer and Executive Vice President, Strategic Planning and Corporate Affairs, ONEOK
		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	55	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
Charles M. Kelley	61	2018 to present	Senior Vice President, Natural Gas, ONEOK
Senior Vice President, Natural Gas		2017 to 2018	Senior Vice President, Natural Gas Gathering & Processing, ONEOK
		2015 to 2017	Senior Vice President, Corporate Planning and Development, ONEOK and ONEOK Partners
		2014 to 2015	Vice President, Corporate Development, ONEOK and ONEOK Partners
Sheridan C. Swords	50	2017 to present	Senior Vice President, Natural Gas Liquids, ONEOK
Senior Vice President, Natural Gas Liquids		2013 to 2017	Senior Vice President, Natural Gas Liquids, ONEOK Partners
Stephen B. Allen	46	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
Mary M. Spears	40	2019 to present	Vice President and Chief Accounting Officer, ONEOK
Vice President and Chief Accounting Officer		2015 to 2019	Director, SEC Reporting, ONEOK
		2015 to 2017	Director, SEC Reporting, ONEOK Partners
		2009 to 2015	Director, Natural Gas Liquids Accounting, 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, Corporate Sustainability Report, 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.

In addition to our filings with the SEC and materials posted on our website, we also use social media platforms 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.

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.

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 dependent upon production from natural gas and crude oil wells, which naturally declines 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 facilities, 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' ability to obtain necessary permits, drilling rights and surface access in a timely manner and on reasonable terms;
- natural gas field characteristics and production performance; and
- capacity constraints on natural gas, crude oil and NGL 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 affect adversely our business, results of operations, financial position and cash flows, and our ability to pay cash dividends.

Continued development of supply sources outside of our operating regions could impact demand for our services.

Natural gas production areas outside of our operating regions may compete with natural gas originating in production areas connected to our systems. For example, increased production in the Marcellus Shale may cause natural gas and NGLs 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. In our Natural Gas Gathering and Processing segment, the development of 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 supply sources that are closer to the end-use markets could reduce demand for our services. Either of these possibilities could result in lower revenues, which could affect adversely our business, results of operations, financial position and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions, which could affect 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 NGL gathering, transportation and distribution pipelines, storage facilities and processing and fractionation facilities, which include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes and the performance of 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, and other similar events beyond our control. Also, the United States government warned that energy assets, specifically the nation's pipeline infrastructure, may be targets of terrorist attacks. An act of terrorism could target our facilities, those of our suppliers or customers or those of other pipelines. A casualty occurrence may 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 our revenues 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 affect adversely our business, results of operations, financial position and cash flows. 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.

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

An adverse change in economic conditions worldwide or in the economic regions in which we operate could negatively affect 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 services and products. 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 suppliers and customers, which, in turn, could have a negative impact on their ability to meet their obligations to us. Periods of severe volatility in equity and credit markets may disrupt our access to such markets, make it difficult to obtain financing necessary to expand facilities or acquire assets, increase financing costs and result in the imposition of restrictive financial covenants. If adverse global or regional economic and market conditions remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, results of operations, financial position, cash flows and liquidity.

Increased regulation of exploration and production activities, including hydraulic fracturing, well setbacks and disposal of waste water, could result in reductions or delays in drilling and completing new crude oil and natural gas wells.

The crude oil and natural gas industry is relying increasingly on 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 crude oil and natural gas production. Legislation or regulations placing restrictions on exploration and production activities, including hydraulic fracturing and disposal of waste water, could result in operational delays, increase operating costs and additional regulatory burdens on exploration and production operators. Any of these factors could reduce their production of unprocessed natural gas and, in turn, affect adversely our revenues and results of operations by decreasing the volumes of natural gas and NGLs gathered, treated, processed, fractionated and transported on our or our joint ventures' assets.

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

Our natural gas and NGL pipelines, processing, fractionation and storage assets compete with other pipelines, processing, fractionation and storage assets 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 assets, which could affect adversely our business, results of operations, financial position and cash flows.

Growing our business by constructing new pipelines and facilities 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.

To expand our business, we regularly construct new and modify or expand existing pipelines and gathering, processing, storage and fractionation facilities. The construction and modification of these facilities may involve the following risks:

- projects may require significant capital expenditures, which may exceed our estimates, and involve 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 construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize;
- opposition from environmental groups, landowners, tribal groups, local groups and other advocates could result in 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
- 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 adversely our business, results of operations, financial position and cash flows.

Estimates of hydrocarbon reserves may be inaccurate which could result in lower than anticipated volumes.

We may not be able to accurately estimate hydrocarbon reserves and production volumes expected to be delivered to us for a variety of reasons, including the unavailability of sufficiently detailed information and unanticipated changes in producers' expected drilling schedules. Accordingly, we may not have accurate estimates of total reserves serviced by our assets, the anticipated life of such reserves or the expected volumes to be produced from those reserves. In such event, if we are unable to secure additional sources, then the volumes that we gather or process in the future could be less than anticipated. A decline in such volumes could affect adversely our business, results of operations, financial position 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 affect adversely our business, results of operations, financial position 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.

We do not hedge fully against commodity price risk or interest rate risk, including 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 future cash flows and 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;
- the seasonal price differentials in natural gas and NGLs related to our storage operations;
- the price risk related to electric costs to operate our facilities, primarily in Texas; 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, futures, forwards and options. However, we do not hedge fully against commodity price changes, and we therefore retain some exposure to market risk. Further, 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 fixed-rate swap instruments to hedge variable-rate instruments and the fixed rate exceeds the variable rate. Finally, hedging arrangements for forecasted sales and purchases are used to reduce our exposure to commodity price fluctuations and may limit the benefit we would otherwise receive if market prices for natural gas, crude oil and NGLs differ from the stated price in the hedge instrument for these commodities.

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 information technology 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, financial or tax requirements;
- providing data security; and
- other processes 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 individual 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 and sophistication 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, physical damages, 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. Cybersecurity, physical security and the continued development and enhancement of our controls, processes and practices designed to protect our enterprise, information systems and data from attack, damage or unauthorized access and to identify and appropriately report cyberattacks, remain a priority for us. 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.

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 N of the Notes to Consolidated Financial Statements in this Annual Report.

Our insurance may not cover all environmental risks and has limits on coverage in the event an environmental claim is made against us. Our business may be affected 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 adversely our products and activities, and federal and state agencies could impose additional safety requirements, all of which could affect adversely 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 on the federal, state and regional levels, may require us either to limit GHG emissions associated with our operations, pay additional taxes or to purchase allowances for such emissions. These legislative and/or regulatory initiatives 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, financial position or cash flows could be affected adversely if such costs are not recovered or otherwise passed on to our customers. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations or when they may become effective.

We may be subject to physical and financial risks associated with climate change and changes in investor sentiment towards climate change may affect the demand for our securities.

The threat of global climate change may create physical and financial risks to our business. 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.

Due to climate change concerns, some investors may choose to either not invest, or reduce their investment, in companies that explore for, produce, process, transport or sell products derived from hydrocarbons. If this investor sentiment increases, we may see reduced demand for our securities, which could impact our liquidity or the value of our securities. In addition, 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.

Changes in regulatory policies, public sentiment or technology due to the threat of climate change that result in a reduction in the demand for hydrocarbon products, restrictions on their use, or increased use of renewable energy could reduce future demand for hydrocarbons and reduce volumes available to us for gathering, processing, fractionation, transportation, storage and marketing. Finally, increasing attention to climate change and the impacts of GHG emissions has resulted in an increased likelihood of governmental investigations, regulation and private litigation, which could increase our costs or otherwise affect adversely our business.

Our business is subject to regulatory oversight and potential penalties.

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

- regulatory approval and review of certain of our 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 our operations. We cannot guarantee that state or federal regulators will not challenge our safety practices or 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.

Under the Natural Gas Act, which is applicable to our interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to our NGL pipelines, our interstate transportation rates are regulated by the FERC and many changes to our pipeline tariffs must be approved in a regulatory proceeding. Additionally, either shippers, the FERC and/or state regulatory agencies may investigate our tariff rates which could result in, among other things, being ordered to reduce rates or make refunds to shippers.

Failure to comply with all applicable state or federal statutes, rules and regulations and orders could bring substantial penalties and fines.

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.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs.

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, at times, 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 challenges of attracting new, qualified 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 affect adversely our labor productivity and costs and our ability to expand operations in the event there is an increase in the demand for our services and products, which could affect adversely our business, results of operations, financial position 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 NGL 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: (i) the significant quantities (*i.e.*, thousands) of measurement equipment that we use across our natural gas and NGL systems, primarily around our gathering and processing assets; (ii) varying qualities of natural gas in the streams gathered and processed through our systems and the mixed nature of NGLs gathered and fractionated; and (iii) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that may occur on our systems, which could affect adversely our business, results of operations, financial position and cash flows.

Many of our 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 adversely our business, results of operations, financial position and 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%) 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, subject to contractual restrictions, 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 who may have business interests different from ours.

We do not operate all of our joint-venture assets nor do we employ directly all of the persons responsible for providing 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 results of operations.

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 operator or an outsourced service provider. We may have to contract elsewhere for outsourced 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 affect adversely our business and results of operations.

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 affect adversely our business, results of operations, financial position and cash flows.

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.

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.

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, our access to capital markets and the cost of capital.

Our employees or directors may engage in misconduct or other improper activities, including noncompliance with regulatory standards and requirements.

As with all companies, we are exposed to the risk of employee fraud or other misconduct. Our Board of Directors has adopted a code of business conduct and ethics that applies to our directors, officers (including our principal executive and financial officers, principal accounting officer, controllers and other persons performing similar functions) and all other employees. We require all directors, officers and employees to adhere to our code of business conduct and ethics in addressing the legal and ethical issues encountered in conducting their work for our company. Our code of business conduct and ethics requires, among other things, that our directors, officers and employees avoid conflicts of interest, comply with all applicable laws and other legal requirements, conduct business in an honest and ethical manner and otherwise act with integrity and in our company's best interest. All directors, officers and employees are required to report any conduct that they believe to be an actual or apparent violation of our code of business conduct and ethics. However, it is not always possible to identify and deter misconduct, and the precautions we take to detect and prevent this activity may not be effective in controlling unknown or unmanaged risks or losses or in protecting us from governmental investigations or other actions or lawsuits stemming from a failure to comply with such laws or regulations. If any such actions are instituted against us, and we are not successful in defending ourselves or asserting our rights, those actions could affect adversely our reputation, business, results of operations, financial position and cash flows.

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.

Any reduction in our credit ratings could affect adversely our business, results of operations, financial position and cash flows.

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 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 M of the Notes to Consolidated Financial Statements in this Annual Report. 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 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 our risk-management policies and procedures 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 affect adversely our business, results of operations, financial position, cash flows 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 counterparties may be similarly affected by changes in economic, regulatory or other factors that may affect our overall credit risk.

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. Our results of operations, cash flows and financial position could be affected adversely by significant fluctuations in interest rates from current levels.

In July 2017, the head of the United Kingdom Financial Conduct Authority announced the desire to phase out the use of LIBOR by the end of 2021. In addition, the U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, a steering committee composed of large US financial institutions, is considering replacing U.S. dollar LIBOR with the Secured Overnight Financing Rate (SOFR), a new index supported by short-term Treasury repurchase agreements. Although there have been some issuances utilizing SOFR, it is unknown whether this alternative reference rate will attain market acceptance as a replacement for LIBOR.

Our $2.5 Billion Credit Agreement and our $1.5 Billion Term Loan Agreement include provisions that grant the agreement's administrative agents with broad discretion to establish a replacement rate for LIBOR, if necessary.

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

As of December 31, 2019, we had total indebtedness of $12.8 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 $2.5 Billion Credit Agreement and $1.5 Billion Term Loan Agreement 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 Operations, in this Annual Report. 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 or comply with financial covenants, 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 any future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the senior notes.

Although many of our operating subsidiaries have guaranteed our 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 and ONEOK Partners' senior notes. Such events of default would entitle the trustee or the holders of 25% in aggregate principal amount of our and 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.

ONEOK, ONEOK Partners and the Intermediate Partnership have cross guarantees in place for our and ONEOK Partners' indebtedness. 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 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 former employees hired before January 1, 2005, and postretirement 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 full-time 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 and postretirement welfare plans, see Note K of the Notes to Consolidated Financial Statements in this Annual Report.

Any sustained declines in equity markets and reductions in bond yields may affect adversely 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 affect adversely our business, financial condition and liquidity.

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 N 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

Our common stock is listed on the NYSE under the trading symbol "OKE." The corporate name ONEOK is used in newspaper stock listings.

At February 18, 2020, there were 14,001 holders of record of our 413,319,000 outstanding shares of common stock.

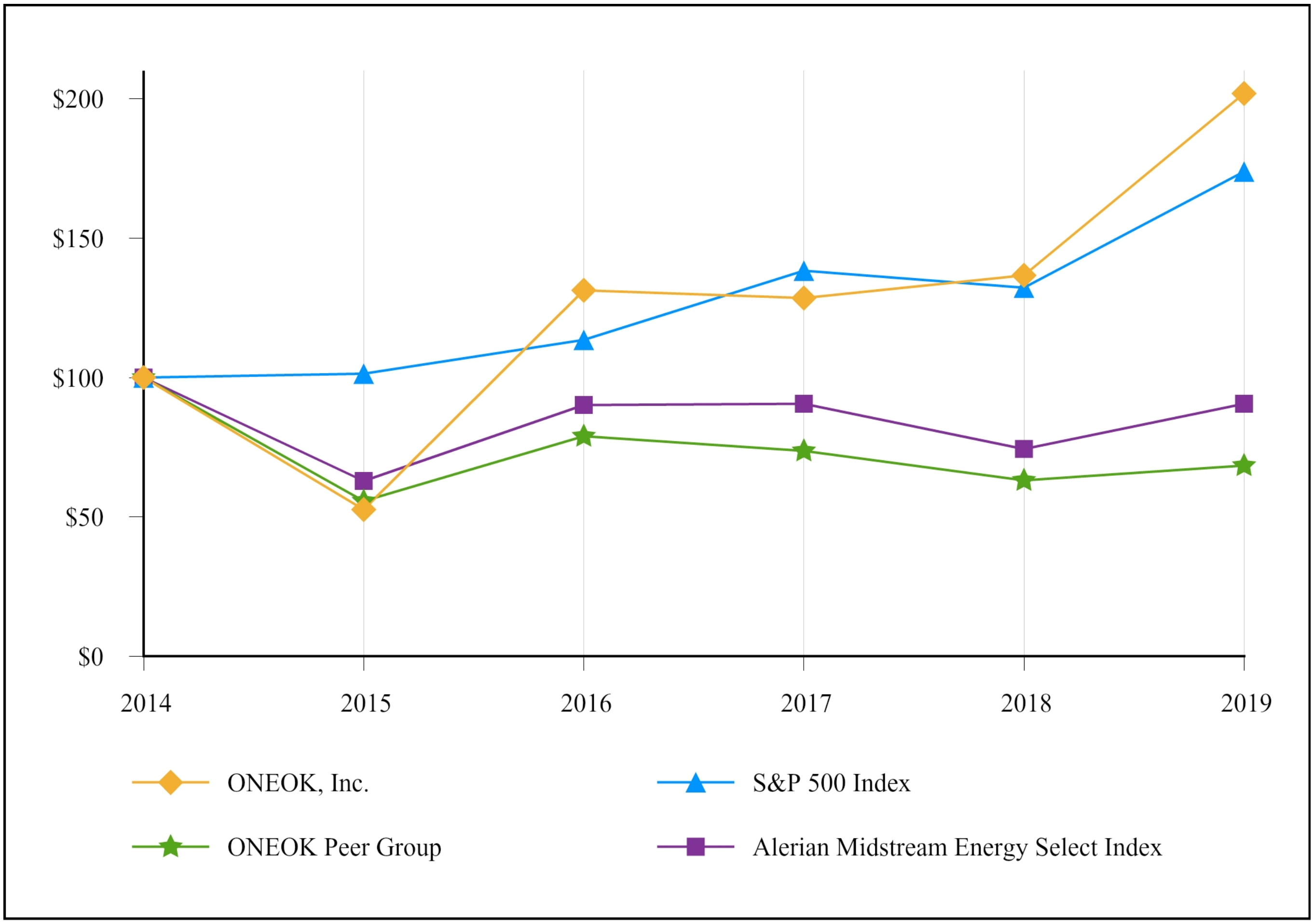
For information regarding our Employee Stock Award Program and other equity compensation plans see Note J of the Notes to Consolidated Financial Statements and "Equity Compensation Plan Information" included in Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, in this Annual Report.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock with the S&P 500 Index, the Alerian Midstream Energy Select Index and a ONEOK Peer Group during the period beginning on December 31, 2014, and ending on December 31, 2019.

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, 2014, and at the End of Every Year Through December 31, 2019.



	Cumulative Total Return									
	Years Ended December 31,									
	2015		2016		2017		2018		2019	
ONEOK, Inc.	$	52.64	$	131.26	$	128.53	$	136.60	**$**	**201.86**
S&P 500 Index	$	101.37	$	113.49	$	138.26	$	132.19	**$**	**173.80**
ONEOK Peer Group (a)	$	55.66	$	78.90	$	73.65	$	63.01	**$**	**68.41**
Alerian Midstream Energy Select Index (b)	$	62.86	$	90.08	$	90.52	$	74.34	**$**	**90.52**

(a) - The ONEOK Peer Group is composed of the following companies: DCP Midstream, LP; Enable Midstream Partners, LP; Energy Transfer LP.; EnLink Midstream, LLC; 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 Midstream Energy Select Index measures the composite performance of approximately 35 North American energy infrastructure companies who are engaged in midstream activities involving energy commodities.

ITEM 6. SELECTED FINANCIAL DATA

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

	Years Ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(Millions of dollars, except per share data)				
Revenues	**$ 10,164.4**	$ 12,593.2	$ 12,173.9	$ 8,920.9	$ 7,763.2
Net income	**$ 1,278.6**	$ 1,155.0	$ 593.5	$ 743.5	$ 379.2
Total assets	**$ 21,812.1**	$ 18,231.7	$ 16,845.9	$ 16,138.8	$ 15,446.1
Long-term debt, including current maturities	**$ 12,487.4**	$ 9,381.0	$ 8,524.3	$ 8,330.6	$ 8,434.2
Earnings per share - total					
Basic	**$ 3.09**	$ 2.80	$ 1.30	$ 1.67	$ 1.17
Diluted	**$ 3.07**	$ 2.78	$ 1.29	$ 1.66	$ 1.16
Dividends declared per share of common stock	**$ 3.53**	$ 3.245	$ 2.72	$ 2.46	$ 2.43

Changes in commodity prices and sales volumes affect both revenue and cost of sales and fuel, and, therefore, the changes in revenue in the above table are largely offset in cost of sales and fuel.

In 2019, we completed underwritten public offerings of $1.25 billion and $2.0 billion senior unsecured notes in March and August, respectively, primarily to fund our capital-growth projects.

Upon adoption of Topic 606 in January 2018, we determined that 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 supplier contracts. Contractual fees in these identified contracts are recorded as a reduction of the commodity purchase price in cost of sales and fuel. In 2017 and prior periods, these fees were recorded as services revenue.

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 the 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 L in the Notes to the Consolidated Financial Statements in this Annual Report.

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 and $264.3 million in 2017 and 2015, 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.

Market Conditions - Volumes increased across our system in our Natural Gas Gathering and Processing and Natural Gas Liquids segments in 2019, compared with 2018, which resulted in higher fee-based earnings, primarily as a result of our completed capital-growth projects, continued drilling and producer improvements in production due to enhanced completion techniques, offset partially by natural production declines.

We experienced fluctuating NGL location price differentials due to increased supply, increased demand in the Mid-Continent region, infrastructure constraints and slower demand growth in the Gulf Coast due primarily to delays in the startup of petrochemical facilities and constrained NGL export facilities. The Conway-to-Mont Belvieu OPIS price differential for ethane in ethane/propane mix averaged $0.07 per gallon in 2019, compared with $0.15 per gallon in 2018, which resulted in lower earnings from our optimization and marketing activities in our Natural Gas Liquids segment. We expect narrower NGL location price differentials in 2020.

Ethane Opportunity - Ethane volumes under long-term contracts delivered to our NGL system averaged 385 MBbl/d in 2019, compared with 380 MBbl/d in 2018, and have generally been increasing since 2017, primarily as a result of NGL demand increasing from exports and petrochemical companies completing ethylene production projects and plant expansions. Our NGL capital-growth projects are expected to help alleviate system constraints, enabling additional NGLs, including ethane, to reach the Mont Belvieu, Texas, market center.

Northern Border Pipeline, which provides key natural gas takeaway capacity out of the Williston Basin, recently notified shippers that it plans to place restrictions on the Btu content of the residue natural gas it receives in order to meet downstream pipeline specifications. When these restrictions take effect, natural gas processors in the Williston Basin may recover incremental ethane into the NGL stream in order to lower the Btu content of the residue natural gas delivered to Northern Border Pipeline. As a result, ethane deliveries to our NGL system may increase.

Growth Projects - Our announced large capital-growth projects that have recently been completed or are currently under construction are outlined in the tables below:

Project	Scope	Approximate Costs (a)	Expected Completion
Natural Gas Gathering and Processing		*(In millions)*	
Demicks Lake I plant and related infrastructure	200 MMcf/d processing plant and related gathering infrastructure in the core of the Williston Basin Supported by acreage dedications with long-term primarily fee-based contracts	$400	Completed October 2019
Demicks Lake II plant and related infrastructure	200 MMcf/d processing plant and related gathering infrastructure in the core of the Williston Basin Supported by acreage dedications with long-term primarily fee-based contracts	$410	Completed January 2020
Bear Creek plant expansion and related infrastructure	200 MMcf/d processing plant expansion and related gathering infrastructure in the Williston Basin Supported by acreage dedications with long-term primarily fee-based contracts	$405	First Quarter 2021
Demicks Lake III plant and related infrastructure	200 MMcf/d processing plant and related gathering infrastructure in the core of the Williston Basin Supported by acreage dedications with primarily fee-based contracts	$305	Third Quarter 2021

(a) - Excludes capitalized interest/AFUDC.

Project	Scope	Approximate Costs (a)	Expected Completion
Natural Gas Liquids			
Elk Creek pipeline and related infrastructure	900-mile NGL pipeline from the Williston Basin to the Mid-Continent region, with capacity of up to 240 MBbl/d, and related infrastructure Anchored by long-term contracts Expansion capability up to 400 MBbl/d with additional pump facilities	$1,400	Completed December 2019 (b)
Arbuckle II pipeline and related infrastructure	530-mile NGL pipeline from the STACK area to Mont Belvieu, Texas, with initial capacity up to approximately 400 MBbl/d, and related infrastructure Supported by long-term contracts Expansion capability up to 1 MMBbl/d	$1,360	First Quarter 2020
West Texas LPG pipeline expansion and Arbuckle II connection	Increasing mainline capacity by 80 MBbl/d with additional pump facilities and pipeline looping Connecting West Texas LPG pipeline system to the Arbuckle II pipeline Supported by long-term dedicated production from six third-party processing plants expected to produce up to 60 MBbl/d	$295	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 (c)
Bakken NGL pipeline extension	75-mile NGL pipeline in the Williston Basin connecting to a third-party processing plant Supported by a long-term contract with a minimum volume commitment	$100	Fourth Quarter 2020
Arbuckle II extension project and additional gathering infrastructure	Provide additional takeaway capacity in the STACK area Allow increasing volumes on the Elk Creek pipeline access to fractionation capacity at Mont Belvieu, Texas	$240	First Quarter 2021
Arbuckle II pipeline expansion	Increasing mainline capacity with additional pump facilities Increases capacity to 500 MBbl/d	$60	First Quarter 2021
MB-5 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	$750	First Quarter 2021
West Texas LPG pipeline expansion	Increasing mainline capacity by 40 MBbl/d Supported by long-term dedicated production from third-party processing plants expected to produce up to 45 MBbl/d	$145	First Quarter 2021
Mid-Continent fractionation facility expansions	65 MBbl/d of expansions at our Mid-Continent NGL facilities	$150	First Quarter 2021 (d)
West Texas LPG pipeline expansion	Increasing mainline capacity by 100 MBbl/d Fully contracted with long-term dedicated production from third-party processing plants	$310	Second Quarter 2021
Elk Creek pipeline expansion	Increasing mainline capacity to 400 MBbl/d with additional pump facilities Supported by long-term dedicated production from ONEOK and third-party processing plants	$305	Third Quarter 2021 (e)

(a) - Excludes capitalized interest/AFUDC.
(b) - In July 2019, we completed the southern section of the pipeline from the Powder River Basin to our existing Mid-Continent NGL facilities. In December 2019, we completed the northern section of the pipeline from the Williston Basin to the Powder River Basin.
(c) - We completed 75 MBbl/d in December 2019, with the remaining 50 MBbl/d to be completed in the first quarter 2020.
(d) - We expect to complete 15 MBbl/d in the third quarter 2020, with the remaining 50 MBbl/d expected to be completed in the first quarter 2021.
(e) - We expect a portion of this incremental capacity to be available as early as first quarter 2021.

Debt Issuances and Repayments - In August 2019, we completed an underwritten public offering of $2.0 billion senior unsecured notes consisting of $500 million, 2.75% senior notes due 2024; $750 million, 3.4% senior notes due 2029; and $750 million, 4.45% senior notes due 2049. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $1.97 billion and were used for general corporate purposes, including funding of capital expenditures and repayment of existing indebtedness. Repayments included the redemption of our $300 million, 3.8% senior notes due March

2020 at a redemption price of $308 million in September 2019 and the repayment of $250 million of our $1.5 Billion Term Loan agreement in August 2019.

In March 2019, we completed an underwritten public offering of $1.25 billion senior unsecured notes consisting of $700 million, 4.35% senior notes due 2029 and an additional issuance of $550 million of our existing 5.2% senior notes due 2048. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, and exclusive of accrued interest, were $1.23 billion. During the six months ended June 30, 2019, we drew the remaining $950 million under our $1.5 Billion Term Loan Agreement. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

Also, in March 2019, we repaid our $500 million, 8.625% senior notes at maturity with a combination of cash on hand and short-term borrowings.

Dividends - During 2019, we paid dividends totaling $3.53 per share, an increase of 9% from the $3.245 per share paid in 2018. In February 2020, we paid a quarterly dividend of $0.935 per share ($3.74 per share on an annualized basis), an increase of 9% compared with the same quarter in the prior year. Our dividend growth is due to the increase in cash flows resulting from 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, 2019	2018	2017	Variances 2019 vs. 2018 Increase (Decrease)	Variances 2018 vs. 2017 Increase (Decrease)
			(*Millions of dollars*)		
Revenues					
Commodity sales	**$ 8,916.1**	$ 11,395.6	$ 9,862.7	**$ (2,479.5)**	$ 1,532.9
Services	**1,248.3**	1,197.6	2,311.2	**50.7**	(1,113.6)
Total revenues	**10,164.4**	12,593.2	12,173.9	**(2,428.8)**	419.3
Cost of sales and fuel (exclusive of items shown separately below)	**6,788.0**	9,422.7	9,538.0	**(2,634.7)**	(115.3)
Operating costs	**982.9**	907.0	822.7	**75.9**	84.3
Depreciation and amortization	**476.5**	428.6	406.3	**47.9**	22.3
Impairment of long-lived assets	**—**	—	16.0	**—**	(16.0)
(Gain) loss on sale of assets	**2.6**	(0.6)	(0.9)	**(3.2)**	(0.3)
Operating income	**$ 1,914.4**	$ 1,835.5	$ 1,391.8	**$ 78.9**	$ 443.7
Equity in net earnings from investments	**$ 154.5**	$ 158.4	$ 159.3	**$ (3.9)**	$ (0.9)
Impairment of equity investments	**$ —**	$ —	$ (4.3)	**$ —**	$ (4.3)
Interest expense, net of capitalized interest	**$ (491.8)**	$ (469.6)	$ (485.7)	**$ 22.2**	$ (16.1)
Net income	**$ 1,278.6**	$ 1,155.0	$ 593.5	**$ 123.6**	$ 561.5
Adjusted EBITDA	**$ 2,580.2**	$ 2,447.5	$ 1,986.9	**$ 132.7**	$ 460.6
Capital expenditures	**$ 3,848.3**	$ 2,141.5	$ 512.4	**$ 1,706.8**	$ 1,629.1

See reconciliation of net income to adjusted EBITDA in the "Adjusted EBITDA" section.

Changes in commodity prices and sales volumes affect both revenues and cost of sales and fuel in our Consolidated Statements of Income, and, therefore, the impact is largely offset between these line items.

2019 vs. 2018 - Operating income increased primarily as a result of the following:

- *Natural Gas Gathering and Processing* - an increase of $95.5 million due primarily to natural gas volume growth, offset partially by a decrease of $20.9 million due primarily to lower realized NGL and natural gas prices, net of hedges;

- *Natural Gas Liquids* - an increase of $148.1 million in exchange services due primarily to higher volumes and average fee rates, offset partially by a decrease of $60.2 million in optimization and marketing due primarily to wider location price differentials in the prior year; and
- *Natural Gas Pipelines* - an increase of $56.5 million from higher transportation services, offset partially by a decrease of $9.1 million from lower net retained fuel and timing of equity gas sales; offset partially by
- an increase of $75.9 million in operating costs due primarily to higher employee-related costs associated with labor and benefits, spending on routine maintenance projects and ad valorem taxes due to the growth of our operations; and
- an increase of $47.9 million in depreciation expense due to capital projects placed in service.

Net income increased for the year ended December 31, 2019, compared with the same period in 2018, due to the items discussed above and higher allowance for equity funds used during construction related to our capital-growth projects, offset partially by higher interest expense related to our underwritten public debt offerings in March and August 2019.

Capital expenditures increased due primarily to spending on our announced capital-growth projects.

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

Selected Financial Results and Operating Information the Year Ended December 31, 2018 vs. 2017 - The consolidated and segment financial results and operating information for the year ended December 31, 2018, compared with the year ended December 31, 2017, are included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations of our 2018 Annual Report on Form 10-K, which is available via the SEC's website at www.sec.gov and our website at www.oneok.com.

Natural Gas Gathering and Processing

Growth Projects - Our Natural Gas Gathering and Processing segment is investing in growth projects in NGL-rich areas in the Williston Basin that we expect will enable us to meet the needs of crude oil and natural gas producers in those areas. See "Growth Projects" in the "Recent Developments" section for discussion of our announced capital-growth projects.

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	
				2019 vs. 2018	**2018 vs. 2017**
Financial Results	**2019**	**2018**	**2017**	**Increase (Decrease)**	
			(Millions of dollars)		
NGL sales	**$ 1,024.3**	$ 1,567.2	$ 1,208.0	**$ (542.9)**	$ 359.2
Condensate sales	**200.1**	208.8	103.2	**(8.7)**	105.6
Residue natural gas sales	**966.1**	1,084.2	856.3	**(118.1)**	227.9
Gathering, compression, dehydration and processing fees and other revenue	**178.1**	174.4	859.1	**3.7**	(684.7)
Cost of sales and fuel (exclusive of depreciation and operating costs)	**(1,302.3)**	(2,041.4)	(2,216.4)	**(739.1)**	(175.0)
Operating costs, excluding noncash compensation adjustments	**(352.8)**	(357.7)	(302.6)	**(4.9)**	55.1
Equity in net earnings (loss) from investments, excluding noncash impairment charges	**(6.3)**	0.4	12.1	**(6.7)**	(11.7)
Other	**(4.5)**	(4.3)	(1.2)	**(0.2)**	(3.1)
Adjusted EBITDA	**$ 702.7**	$ 631.6	$ 518.5	**$ 71.1**	$ 113.1
Impairment of equity investments	**$ —**	$ —	$ (4.3)	**$ —**	$ (4.3)
Capital expenditures	**$ 926.5**	$ 694.6	$ 284.2	**$ 231.9**	$ 410.4

See reconciliation of net income to adjusted EBITDA in the "Adjusted EBITDA" section.

Changes in commodity prices and sales volumes affect both revenue and cost of sales and fuel, and, therefore, the impact is largely offset between these line items.

2019 vs. 2018 - Adjusted EBITDA increased $71.1 million, primarily as a result of the following:

- an increase of $95.5 million due primarily to natural gas volume growth in the Williston Basin and STACK and SCOOP areas, offset partially by natural production declines; and
- a decrease of $4.9 million in operating costs due primarily to lower outside services and materials and supplies, offset partially by higher employee-related costs and ad valorem taxes due primarily to the growth of our operations; offset partially by
- a decrease of $20.9 million due primarily to lower realized NGL and natural gas prices, net of hedges; and
- a decrease of $6.7 million due primarily to lower equity in net earnings from investments due to a decrease in supply volumes in the dry natural gas area of the Powder River Basin.

Capital expenditures increased due primarily to spending on our announced capital-growth projects.

	Years Ended December 31,		
Operating Information (a)	**2019**	**2018**	**2017**
Natural gas gathered (*BBtu/d*)	**2,753**	2,546	2,211
Natural gas processed (*BBtu/d*) (b)	**2,555**	2,382	2,056
NGL sales (*MBbl/d*)	**224**	198	187
Residue natural gas sales (*BBtu/d*) (b)	**1,201**	1,088	896
Average fee rate (*$MMBtu*)	**$ 0.92**	$ 0.90	$ 0.86

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

2019 vs. 2018 - Natural gas gathered, natural gas processed, NGL sales and residue natural gas sales volumes increased in 2019, compared with 2018, due primarily to our capital-growth projects and continued producer improvements in production due to enhanced completion techniques, offset partially by natural production declines.

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

Natural Gas Liquids

Growth Projects - Our Natural Gas Liquids segment invests in projects to transport, fractionate, store and deliver to market centers NGL supply from shale and other resource development areas. Our growth strategy is focused around connecting diversified supply basins from the Rocky Mountain region through the Mid-Continent region and the Permian Basin with NGL product demand from the petrochemical industry and NGL export demand in the Gulf Coast. Growing crude oil, natural gas and NGL production together with higher petrochemical and export demand have resulted in us making additional capital investments to expand our infrastructure and alleviate system constraints. See "Growth Projects" in the "Recent Developments" section for discussion of our announced capital-growth projects.

We continue to evaluate opportunities to increase the capacity of our gathering, fractionation, storage and distribution assets or construct new assets to connect supply growth from the Williston and Powder River Basins, Mid-Continent region and Permian Basin with end-use markets.

In 2019, we connected seven third-party natural gas processing plants and one affiliate natural gas processing plant to our NGL system, five in the Mid-Continent region, one in the Permian Basin and two in the Rocky Mountain region. In addition, six third-party natural gas processing plants connected to our system were expanded, two in the Mid-Continent region, two in the Permian Basin and two in the Rocky Mountain 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 2019 vs. 2018	Variances 2018 vs. 2017
Financial Results	**2019**	**2018**	**2017**	**Increase (Decrease)**	
			(*Millions of dollars*)		
NGL and condensate sales	**$ 7,910.8**	$ 10,319.9	$ 8,998.9	**$ (2,409.1)**	$ 1,321.0
Exchange service revenues and other	**424.2**	415.7	1,430.3	**8.5**	(1,014.6)
Transportation and storage revenues	**197.5**	199.0	197.0	**(1.5)**	2.0
Cost of sales and fuel (exclusive of depreciation and operating costs)	**(6,690.9)**	(9,176.8)	(9,176.5)	**(2,485.9)**	0.3
Operating costs, excluding noncash compensation adjustments	**(434.4)**	(378.3)	(351.3)	**56.1**	27.0
Equity in net earnings from investments	**65.1**	67.1	59.9	**(2.0)**	7.2
Other	**(6.5)**	(6.0)	(3.4)	**(0.5)**	(2.6)
Adjusted EBITDA	**$ 1,465.8**	$ 1,440.6	$ 1,154.9	**$ 25.2**	$ 285.7
Capital expenditures	**$ 2,796.6**	$ 1,306.3	$ 114.3	**$ 1,490.3**	$ 1,192.0

See reconciliation of net income to adjusted EBITDA in the "Adjusted EBITDA" section.

Changes in commodity prices and sales volumes affect both revenues and cost of sales and fuel, and, therefore, the impact is largely offset between these line items.

2019 vs. 2018 - Adjusted EBITDA increased $25.2 million, primarily as a result of the following:

- an increase of $148.1 million in exchange services due to $150.2 million in higher volumes primarily in the Rocky Mountain region, the Permian Basin and the STACK and SCOOP areas, and $91.5 million in higher average fee rates primarily in the Permian Basin and the Rocky Mountain region, offset partially by $64.9 million due primarily to higher third-party transportation and fractionation costs, $25.0 million due primarily to narrower product price differentials and $5.8 million related to higher unfractionated NGLs in inventory; offset partially by
- a decrease of $60.2 million in optimization and marketing due primarily to a decrease of $93.8 million related to wider location price differentials in the prior year, particularly in the third quarter 2018, and $5.1 million in lower earnings related primarily to product price differentials, offset partially by higher marketing earnings of $38.5 million related primarily to the sale of NGL products previously held in inventory; and
- an increase of $56.1 million in operating costs due primarily to higher employee-related costs associated with labor and benefits due to the growth of our operations, and spending on routine maintenance projects.

Capital expenditures increased due primarily to our announced capital-growth projects.

	Years Ended December 31,		
Operating Information	**2019**	**2018**	**2017**
Raw feed throughput (*MBbl/d*) (a)	**1,079**	1,010	895
NGLs transported - gathering lines (MBbl/d) (b)	**988**	912	812
NGLs fractionated (MBbl/d) (c)	**726**	715	621
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix (*$/gallon*)	**$ 0.07**	$ 0.15	$ 0.05

(a) - Represents physical raw feed volumes on which we charge a fee for transportation and/or fractionation services.
(b) - Includes volumes for consolidated entities only.
(c) - Includes volumes at company-owned and third-party facilities.

2019 vs. 2018 - Raw feed throughput volumes increased primarily in the Rocky Mountain region, the Permian Basin and the STACK and SCOOP areas as a result of our completed capital-growth projects, continued drilling and producer improvements in production due to enhanced completion techniques, offset partially by natural production declines and lower volumes in the Mid-Continent region due primarily to lower ethane volumes.

Natural Gas Pipelines

Growth Projects - 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. The development of shale has continued to increase available natural gas supply, and we expect producers and natural gas processors to require incremental transportation services in the future as additional supply is developed.

We expanded our natural gas pipeline infrastructure in Oklahoma and the Permian Basin. The projects included an eastbound expansion of our ONEOK Gas Transportation system by 150 MMcf/d from the STACK and SCOOP areas to an interstate pipeline delivery point in eastern Oklahoma, a westbound expansion of our ONEOK Gas Transportation system by 100 MMcf/d from the STACK area to multiple interstate pipeline delivery points in western Oklahoma and an expansion of our WesTex Transmission system by 300 MMcf/d from the Permian Basin to interstate pipeline delivery points in the Texas Panhandle. Additionally, we completed an expansion project on our Roadrunner joint venture to make the pipeline bidirectional, which resulted in approximately 1.0 Bcf/d of eastbound transportation capacity from the Delaware Basin to the Waha area.

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

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:

	Years Ended December 31,			Variances 2019 vs. 2018	Variances 2018 vs. 2017
Financial Results	**2019**	**2018**	**2017**	**Increase (Decrease)**	
		(*Millions of dollars*)			
Transportation revenues	**$ 393.7**	$ 343.0	$ 327.9	**$ 50.7**	$ 15.1
Storage revenues	**72.6**	72.0	66.5	**0.6**	5.5
Natural gas sales and other revenues	**5.7**	16.7	25.5	**(11.0)**	(8.8)
Cost of sales and fuel (exclusive of depreciation and operating costs)	**(4.6)**	(16.0)	(43.4)	**(11.4)**	(27.4)
Operating costs, excluding noncash compensation adjustments	**(150.8)**	(139.2)	(123.1)	**11.6**	16.1
Equity in net earnings from investments	**95.7**	90.8	87.3	**4.9**	3.5
Other	**(3.5)**	(1.0)	(0.9)	**(2.5)**	(0.1)
Adjusted EBITDA	**$ 408.8**	$ 366.3	$ 339.8	**$ 42.5**	$ 26.5
Capital expenditures	**$ 99.2**	$ 119.2	$ 95.6	**$ (20.0)**	$ 23.6

See reconciliation of net income to adjusted EBITDA in the "Adjusted EBITDA" section.

2019 vs. 2018 - Adjusted EBITDA increased $42.5 million primarily as a result of the following:

- an increase of $56.5 million from higher transportation services due primarily to firm transportation capacity contracted due to our completed expansion projects; and
- an increase of $4.9 million from higher equity in net earnings due primarily to firm transportation capacity contracted on Roadrunner; offset partially by
- an increase of $11.6 million in operating costs due primarily to employee-related costs associated with labor and benefits and ad valorem taxes due to the growth of our operations; and
- a decrease of $9.1 million from lower net retained fuel and timing of equity gas sales.

Capital expenditures decreased due primarily to timing of maintenance projects and capital-growth projects.

	Years Ended December 31,		
Operating Information (a)	**2019**	**2018**	**2017**
Natural gas transportation capacity contracted (*MDth/d*)	**7,618**	6,846	6,611
Transportation capacity contracted	**98%**	96%	94%

(a) - Includes volumes for consolidated entities only.

2019 vs. 2018 - Natural gas transportation capacity contracted increased due to our completed expansion projects on our ONEOK Gas Transportation and WesTex Transmission systems, which are both substantially contracted.

Roadrunner, in which we have a 50% ownership interest, has contracted all of its westbound capacity through 2041.

Northern Border Pipeline, in which we have a 50% ownership interest, has contracted substantially all of its long-haul transportation capacity through the fourth quarter 2020.

In June 2019, our subsidiary, Viking Gas Transmission Company, filed a proposed change in rates pursuant to Section 4 of the Natural Gas Act with the FERC. In February 2020, all parties agreed to a settlement in principle and plan to present it to FERC for approval. We do not expect the ultimate outcome to impact materially our results of operations.

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. 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 share 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.

The following table sets forth a reconciliation of net income, the nearest comparable GAAP financial performance measure, to adjusted EBITDA for the periods indicated:

	Years Ended December 31,		
(*Unaudited*)	**2019**	**2018**	**2017**
Reconciliation of net income to adjusted EBITDA	(*Thousands of dollars*)		
Net income	**$ 1,278,577**	$ 1,155,032	$ 593,519
Add:			
Interest expense, net of capitalized interest	**491,773**	469,620	485,658
Depreciation and amortization	**476,535**	428,557	406,335
Income taxes	**372,414**	362,903	447,282
Impairment charges	**—**	—	20,240
Noncash compensation expense	**26,699**	37,954	13,421
Equity AFUDC and other noncash items (a)	**(65,811)**	(6,545)	20,398
Adjusted EBITDA	**$ 2,580,187**	$ 2,447,521	$ 1,986,853
Reconciliation of segment adjusted EBITDA to adjusted EBITDA			
Segment adjusted EBITDA:			
Natural Gas Gathering and Processing	**$ 702,650**	$ 631,607	$ 518,472
Natural Gas Liquids	**1,465,765**	1,440,605	1,154,939
Natural Gas Pipelines	**408,816**	366,251	339,818
Other (b)	**2,956**	9,058	(26,376)
Adjusted EBITDA	**$ 2,580,187**	$ 2,447,521	$ 1,986,853

(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 N of the Notes to Consolidated Financial Statements in this Annual Report for a discussion of regulatory matters.

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 affect adversely our consolidated results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

General - Our primary sources of cash inflows are operating cash flows, proceeds from our commercial paper program and our $2.5 Billion Credit Agreement, debt issuances and the issuance of common stock for our liquidity and capital resources requirements. In addition, we expect cash outflows related to i) capital expenditures, ii) interest and repayment of debt maturities and iii) dividends paid to shareholders. We expect our cash outflows related to capital expenditures to decrease in 2020 relative to 2019 due to our completed capital-growth projects. We expect dividends paid to continue to increase due to earnings growth from capital projects and higher anticipated dividends per share, subject to declaration by our Board of Directors.

We expect our sources of cash inflows to provide sufficient resources to finance our operations, capital expenditures and quarterly cash dividends, including expected future dividend increases. Our $2.5 Billion Credit Agreement, which expires in June 2024, provides significant liquidity to fund capital expenditures and repay existing indebtedness. We may access the capital markets to issue debt or equity securities as we consider prudent to provide additional liquidity to refinance existing debt, improve credit metrics or to fund capital expenditures. Although we expect to continue to fund capital projects primarily with cash from operations, short-term borrowings and long-term debt, we continue to have access to $550 million available through our "at-the-market" equity program and the ability to issue equity and other securities under our universal shelf registration statement.

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 C 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. As of December 31, 2019, we were in compliance with all covenants of the $2.5 Billion Credit Agreement.

At December 31, 2019, we had no borrowings outstanding under our $2.5 Billion Credit Agreement, $220 million of commercial paper outstanding and $21.0 million of cash and cash equivalents.

We had working capital (defined as current assets less current liabilities) deficits of $550.0 million and $709.8 million as of December 31, 2019, and December 31, 2018, respectively. Although working capital is influenced by several factors, including, among other things: (i) the timing of (a) debt and equity issuances, (b) the funding of capital expenditures, (c) scheduled debt payments, and (d) the collection and payment of accounts receivable and payable; and (ii) the volume and cost of inventory and commodity imbalances; our working capital deficit at December 31, 2019, was driven primarily by short-term borrowings and accrued interest and at December 31, 2018, by current maturities of long-term debt. 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 was due to more favorable interest rates. We do not expect this working capital deficit to affect adversely our cash flows or operations.

For additional information on our $2.5 Billion Credit Agreement and commercial paper program, see Note F 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 - In August 2019, we completed an underwritten public offering of $2.0 billion senior unsecured notes consisting of $500 million, 2.75% senior notes due 2024; $750 million, 3.4% senior notes due 2029; and $750 million, 4.45% senior notes due 2049. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were

$1.97 billion. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

In March 2019, we completed an underwritten public offering of $1.25 billion senior unsecured notes consisting of $700 million, 4.35% senior notes due 2029 and an additional issuance of $550 million of our existing 5.2% senior notes due 2048. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, and exclusive of accrued interest, were $1.23 billion. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

In November 2018, we entered into our $1.5 Billion Term Loan Agreement with a syndicate of banks, which was fully drawn as of June 30, 2019. We repaid $250 million of our outstanding balance in August 2019 and have $1.25 billion drawn as of December 31, 2019. Our $1.5 Billion Term Loan Agreement matures in November 2021 and bears interest at LIBOR plus 112.5 basis points based on our current credit ratings. The agreement contains substantially the same covenants as those contained in our $2.5 Billion Credit Agreement. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

Debt Repayments - In September 2019, we redeemed our $300 million, 3.8% senior notes due March 2020 at a redemption price of $308.0 million, including the outstanding principal, plus accrued and unpaid interest, with cash on hand from our public offering of $2.0 billion senior unsecured notes in August 2019.

In August 2019, we repaid $250 million of our $1.5 Billion Term Loan agreement with cash on hand.

In March 2019, we repaid our $500 million, 8.625% senior notes at maturity with a combination of cash on hand and short-term borrowings.

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

Capital Expenditures - 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 and short- and long-term debt.

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

Capital Expenditures	**2019**	**2018**	**2017**
		(*Millions of dollars*)	
Natural Gas Gathering and Processing	**$ 926.5**	$ 694.6	$ 284.2
Natural Gas Liquids	**2,796.6**	1,306.3	114.3
Natural Gas Pipelines	**99.2**	119.2	95.6
Other	**26.0**	21.4	18.3
Total capital expenditures	**$ 3,848.3**	$ 2,141.5	$ 512.4

Capital expenditures increased in 2019, compared with 2018, due primarily to capital-growth projects in progress. We expect our 2020 capital expenditures to decrease relative to 2019 due to our completed capital-growth projects. See discussion of our announced capital-growth projects in the “Recent Developments” section.

The following table summarizes our 2020 projected growth and maintenance capital expenditures, excluding AFUDC and capitalized interest:

2020 Projected Capital Expenditures	
	(*Millions of dollars*)
Growth	$2,250-$2,730
Maintenance	$200-$220
Total projected capital expenditures	$2,450-$2,950

Credit Ratings - Our long-term debt credit ratings as of February 18, 2020, are shown in the table below:

Rating Agency	Long-Term Rating	Short-Term Rating	Outlook
Moody's	Baa3	Prime-3	Positive
S&P	BBB	A-2	Stable

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 our $2.5 Billion Credit Agreement and our $1.5 Billion Term Loan 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 2024. An adverse credit rating change alone is not a default under our $2.5 Billion Credit Agreement or our $1.5 Billion Term Loan 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 common stock dividends declared by our Board of Directors, subject to the rights of the holders of outstanding preferred stock. In 2019, we paid dividends of $3.53 per share, an increase of 9% compared with the prior year. In February 2020, we paid a quarterly dividend of $0.935 per share ($3.74 per share on an annualized basis), an increase of 9% compared with the same quarter in the prior year.

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% per year. In 2019, we paid dividends of $1.1 million for the Series E Preferred Stock. In February 2020, we paid quarterly dividends totaling $0.3 million for the Series E Preferred Stock.

For the years ended December 31, 2019 and 2018, cash flows from operations exceeded cash dividends paid by $489.2 million and $851.7 million, respectively. We expect our cash flows from operations to continue to sufficiently fund our cash dividends. 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.

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, 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,		
	2019	2018	2017
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	**$ 1,946.8**	$ 2,186.7	$ 1,315.4
Investing activities	**(3,768.8)**	(2,114.9)	(567.6)
Financing activities	**1,831.0**	(97.0)	(959.5)
Change in cash and cash equivalents	**9.0**	(25.2)	(211.7)
Cash and cash equivalents at beginning of period	**12.0**	37.2	248.9
Cash and cash equivalents at end of period	**$ 21.0**	$ 12.0	$ 37.2

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. Our operating cash flows can also be impacted by changes in our natural gas and NGL inventory balances, which are driven primarily by commodity prices, supply, demand and the operation of our assets.

2019 vs. 2018 - Cash flows from operating activities, before changes in operating assets and liabilities, increased $130.4 million due primarily to higher earnings resulting from volume growth in the Rocky Mountain region, STACK and SCOOP areas and the Permian Basin in our Natural Gas Liquids segment and the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing segment, as discussed in “Financial Results and Operating Information.”

The changes in operating assets and liabilities decreased operating cash flows $163.9 million for 2019, compared with an increase of $206.4 million for 2018. This change is due primarily to the change in the fair value of our risk-management assets and liabilities; 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 natural gas and NGLs in storage, which vary both from period to period and with the changes in commodity prices.

Investing Cash Flows

2019 vs. 2018 - Cash used in investing activities increased $1.7 billion due primarily to increased capital expenditures related to our capital-growth projects.

Financing Cash Flows

2019 vs. 2018 - Cash from financing activities increased $1.9 billion due primarily to issuances of $3.25 billion in senior unsecured notes, the $700 million net draw on our $1.5 Billion Term Loan Agreement and an increase in proceeds from short-term borrowings, offset partially by a decrease due to issuances of common stock in 2018.

Cash Flow Analysis for the Year Ended December 31, 2018 vs. 2017 - The cash flow analysis for the year ended December 31, 2018, compared with the year ended December 31, 2017, is included in Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations of our 2018 Annual Report on Form 10-K, which is available via the SEC’s website at www.sec.gov and our website at www.oneok.com.

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. Our commodity price risk includes basis risk, which is the difference in price between various locations where commodities are purchased and sold. We record all derivative instruments at fair value, except for normal purchases and normal sales transactions that are expected to result in physical delivery. Many of the contracts in our derivative portfolio are executed in liquid markets where price transparency exists.

Our fair value measurements classified as Level 3 are composed predominantly of exchange-cleared and over-the-counter derivatives to hedge NGL price risk and natural gas basis risk between various transaction locations and the NYMEX Henry Hub. These measurements are based on inputs that may include one or more unobservable inputs, including internally developed commodity price curves, that incorporate market data from broker quotes and third-party pricing services. Our commodity derivatives are generally valued using forward quotes provided by third-party pricing services that are validated with other market data. We believe any measurement uncertainty at December 31, 2019, is immaterial as our Level 3 fair value measurements are based on unadjusted pricing information from broker quotes and third-party pricing services.

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 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.

We assess the effectiveness of hedging relationships at the inception of the hedge by performing an effectiveness test to determine whether they are highly effective. We subsequently assess qualitative factors. 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 effective cash flow hedges. 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 A, B and C 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. 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.

Update - Upon adoption of ASU 2017-04 in January 2020, the requirement to calculate the implied fair value of goodwill under the two-step impairment test was eliminated. See Note A of the Notes to Consolidated Financial Statements in this Annual Report for more information.

Our qualitative goodwill impairment analysis performed as of July 1, 2019, 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.

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

	December 31, 2019	December 31, 2018
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 153,404**	$ 153,404
Natural Gas Liquids	**371,217**	371,217
Natural Gas Pipelines	**156,375**	156,479
Total goodwill	**$ 680,996**	$ 681,100

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 certain nonstrategic long-lived assets and equity investments in North Dakota and Oklahoma.

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

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment - Our property, plant and equipment are depreciated using the straight-line method that incorporates management assumptions regarding useful economic lives and residual values. As we continue to increase capital spending and place additional assets in service, our estimates related to depreciation expense have become more significant and changes in estimated useful lives of our assets could have a material effect on our results of operations. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation expense prospectively. Examples of such circumstances include changes in (i) competition, (ii) laws and regulations that limit the estimated economic life of an asset, (iii) technology that render an asset obsolete, (iv) expected salvage values and (v) forecasts of the remaining economic life for the resource basins where our assets are located, if any.

See Note D of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of property, plant and equipment.

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 2019, 2018 or 2017. Actual results may differ from our estimates resulting in an impact, positive or negative, on our results of operations.

See Note N 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, leases and other long-term obligations as of December 31, 2019. For additional discussion of the debt and lease agreements, see Notes F and O of the Notes to Consolidated Financial Statements in this Annual Report.

	Payments Due by Period						
Contractual Obligations	**Total**	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**
				(Millions of dollars)			
Senior notes	$ 11,322.4	$ —	$ —	$ 1,447.4	$ 925.0	$ 500.0	$ 8,450.0
Commercial paper borrowings	220.0	220.0	—	—	—	—	—
$1.5 Billion Term Loan Agreement	1,250.0	—	1,250.0	—	—	—	—
Guardian Pipeline senior notes	21.3	7.7	7.7	5.9	—	—	—
Interest payments on debt	8,754.2	610.2	601.2	530.8	487.2	442.5	6,082.3
Operating leases	19.6	2.5	2.1	2.0	1.9	1.9	9.2
Finance lease	39.6	4.5	4.5	4.5	4.5	4.5	17.1
Firm transportation and storage contracts	398.4	61.6	48.1	40.1	36.4	34.3	177.9
Financial and physical derivatives	188.1	168.0	20.1	—	—	—	—
Employee benefit plans	81.8	14.1	14.6	13.1	14.5	13.8	11.7
Purchase commitments and other	312.7	54.1	53.9	53.2	50.8	37.8	62.9
Total	$ 22,608.1	$ 1,142.7	$ 2,002.2	$ 2,097.0	$ 1,520.3	$ 1,034.8	$ 14,811.1

Senior notes, $1.5 Billion Term Loan Agreement and commercial paper borrowings - Represents 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 primarily include leases for certain buildings, warehouses, office space, pipeline capacity, land and equipment, including pipeline equipment, rail cars and information technology equipment. As of December 31, 2019, we entered into an additional operating lease that had not yet commenced with total lease payments of $87.8 million over a lease term of 10 years, which is excluded from our table above.

Finance lease - We lease certain compression facilities under a finance lease that has a fixed-price purchase option in 2028.

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, 2019. 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 $12.1 million to our defined benefit pension plan in January 2020 and expect to make $2.0 million in contributions to our other postretirement plans in 2020. See Note K of the Notes to Consolidated Financial Statements in this Annual Report for discussion of our employee benefit plans.

Purchase commitments and other - Purchase commitments include commitments related to our growth capital expenditures and other 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 capital-growth projects and other future operations (including plans to construct additional natural gas and NGL pipelines, processing and fractionation 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," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "might," "outlook," "plan," "potential," "project," "scheduled," "should," "will," 'would," 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 impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to drill and obtain necessary permits; regulatory compliance; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- 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;
- 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;
- demand for our services and products in the proximity of our facilities;
- 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 United States natural gas and crude oil; and
  - availability of additional storage capacity;
- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers', customers' or shippers' facilities;
- 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;
- economic climate and growth in the geographic areas in which we do business;
- the timing and extent of changes in energy commodity prices;
- 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 profitability of assets or businesses acquired or constructed by us;
- the risk of a slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- 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;
- 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 uncontracted capacity in our assets being greater or less than expected;
- 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;

- our ability to control construction costs and completion schedules of our pipelines and other projects;
- 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 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 results of administrative proceedings and litigation, regulatory actions, executive orders, 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 the CFTC;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- the capital-intensive nature of our businesses;
- the mechanical integrity of facilities operated;
- 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 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 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;
- our ability to access capital at competitive rates or on terms acceptable to us;
- the impact and outcome of pending and future litigation;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- our ability to control operating costs and make cost-saving changes;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- the risk inherent in the use of information systems in our respective businesses and those of our counterparties and service providers, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- the impact of potential impairment charges; 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 affect adversely 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.

See Note A of the Notes to Consolidated Financial Statements in this Annual Report for discussion on our accounting policies for our derivative instruments and the impact on our Consolidated Financial Statements.

COMMODITY PRICE RISK

As part of our hedging strategy, we use commodity derivative financial instruments and physical-forward contracts described in Note C 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. Under certain POP with fee contracts, our contractual 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, 2020		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (*MBbl/d*) - Conway/Mont Belvieu	10.3	$ 0.55 / gallon	63%
Condensate (*MBbl/d*) - WTI-NYMEX	3.0	$ 54.08 / Bbl	62%
Natural gas (*BBtu/d*) - NYMEX and basis	125.0	$ 2.39 / MMBtu	76%

	Year Ending December 31, 2021		
	Volumes Hedged	Average Price	Percentage Hedged
Natural gas (*BBtu/d*) - NYMEX and basis	36.4	$ 2.43 / MMBtu	19%

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, 2019. Condensate sales are typically based on the price of crude oil. Assuming normal operating conditions, we estimate the following for our forecasted equity volumes:

- a $0.01 per gallon change in the composite price of NGLs, excluding ethane, would change adjusted EBITDA for the years ending December 31, 2020 and 2021, by $2.5 million and $3.0 million, respectively;
- a $1.00 per barrel change in the price of crude oil would change adjusted EBITDA for the years ending December 31, 2020 and 2021, by $1.5 million and $1.8 million, respectively; and
- a $0.10 per MMBtu change in the price of residue natural gas would change adjusted EBITDA for the years ending December 31, 2020 and 2021, by $6.1 million and $7.1 million, respectively.

These estimates do not include any effects of hedging or 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.

INTEREST-RATE RISK

We are exposed to interest-rate risk through borrowings under our $2.5 Billion Credit Agreement, $1.5 Billion Term Loan Agreement, commercial paper program and long-term debt issuances. Future increases in LIBOR or the established replacement rate, commercial paper rates or 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. In 2019, we entered into $625 million of forward-starting interest-rate swaps 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. We also settled $1.8

billion of our forward-starting interest-rate swaps related to our underwritten public offering of $1.25 billion senior unsecured notes in March 2019 and $2.0 billion senior unsecured notes in August 2019.

At December 31, 2019 and 2018, we had forward-starting interest-rate swaps with notional amounts totaling $1.8 billion and $3.0 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances. At December 31, 2019 and 2018, we had interest-rate swaps with notional amounts totaling $1.3 billion 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, 2019, we had derivative assets of $0.6 million and derivative liabilities of $201.9 million related to these interest-rate swaps. At December 31, 2018, we had derivative assets of $19.0 million and derivative liabilities of $99.3 million related to these interest-rate swaps.

See Note C of the Notes to Consolidated Financial Statements in this Annual Report 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 2019, no single customer represented more than 10% of our consolidated revenues.

Natural Gas Gathering and Processing - Our Natural Gas Gathering and Processing segment derives services revenue primarily from major and independent 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 less our contractual fees. In 2019 and 2018, approximately 90% and 95%, 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 counterparties are primarily NGL and natural gas gathering and processing companies; major and independent crude oil and natural gas production companies; utilities; large industrial companies; natural gasoline distributors; propane distributors; municipalities; and petrochemical, refining and marketing companies. We charge fees to NGL and natural gas gathering and processing counterparties and NGL pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fees, as we purchase NGLs from our gathering and processing counterparties and deduct our fee from the amounts we remit. We also earn sales revenue on the downstream sales of NGL products. In 2019 and 2018, approximately 80% 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, processors and marketing companies. In 2019 and 2018, approximately 85% 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, 2019 and 2018, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Notes A and P to the consolidated financial statements, the Company changed the manner in which it accounts for revenue from contracts with customers in 2018.

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, included in Management's Report on Internal Control over Financial Reporting appearing 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Valuation of Level 3 Commodity Derivative Assets and Liabilities

As described in Notes A, B and C to the consolidated financial statements, the Company's level 3 commodity derivative assets and liabilities total $55.6 million and $24.8 million, respectively, as of December 31, 2019. As disclosed by management, commodity price risk includes basis risk, which is the difference in price between various locations where commodities are purchased and sold. Management records all derivative instruments at fair value, except for normal purchases and normal sales transactions that are expected to result in physical delivery. Many of the contracts in its derivative portfolio are executed in liquid markets where price transparency exists. Fair value measurements classified as Level 3 are comprised predominantly of exchange-cleared and over-the-counter derivatives to hedge NGL price risk and natural gas basis risk between various transaction locations and the NYMEX Henry Hub. These measurements are based on inputs that may include one or more unobservable inputs, including internally developed commodity price curves, that incorporate market data from broker quotes and third-party pricing services. The commodity derivatives are generally valued using forward quotes provided by third-party pricing services that are validated with other market data.

The principal considerations for our determination that performing procedures relating to the valuation of level 3 commodity derivative assets and liabilities is a critical audit matter are there was significant estimation by management to determine the fair value of these derivatives due to the use of internally developed commodity price curves, that incorporate market data from broker quotes and third-party pricing services. This in turn led to a high degree of subjectivity and effort in evaluating audit evidence related to the valuation. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the valuation of level 3 commodity derivative assets and liabilities, including controls over the Company's model, significant assumptions, and data. These procedures also included, among others, the involvement of professionals with specialized skill and knowledge to assist in developing an independent estimate of the level 3 commodity derivative assets and liabilities and comparison of the independent estimate to management's estimate. Developing the independent estimate involved testing the completeness and accuracy of data used and evaluating management's assumptions related to the internally developed commodity price curves.

/s/ PricewaterhouseCoopers LLP
Tulsa, Oklahoma
February 25, 2020

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

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2019	**2018**	**2017**
	(Thousands of dollars, except per share amounts)		
Revenues			
Commodity sales	**$ 8,916,047**	$ 11,395,642	$ 9,862,652
Services	**1,248,320**	1,197,554	2,311,255
Total revenues (Note P)	**10,164,367**	12,593,196	12,173,907
Cost of sales and fuel (exclusive of items shown separately below)	**6,788,040**	9,422,708	9,538,045
Operations and maintenance	**863,708**	803,146	724,314
Depreciation and amortization	**476,535**	428,557	406,335
Impairment of long-lived assets (Note D)	**—**	—	15,970
General taxes	**119,156**	103,922	98,396
(Gain) loss on sale of assets	**2,575**	(601)	(924)
Operating income	**1,914,353**	1,835,464	1,391,771
Equity in net earnings from investments (Note M)	**154,541**	158,383	159,278
Impairment of equity investments (Note M)	**—**	—	(4,270)
Allowance for equity funds used during construction	**64,815**	7,962	107
Other income	**27,058**	674	15,385
Other expense	**(18,003)**	(14,928)	(35,812)
Interest expense (net of capitalized interest of $107,275, $28,062 and $5,510, respectively)	**(491,773)**	(469,620)	(485,658)
Income before income taxes	**1,650,991**	1,517,935	1,040,801
Income taxes (Note L)	**(372,414)**	(362,903)	(447,282)
Net income	**1,278,577**	1,155,032	593,519
Less: Net income attributable to noncontrolling interests	**—**	3,329	205,678
Net income attributable to ONEOK	**1,278,577**	1,151,703	387,841
Less: Preferred stock dividends	**1,100**	1,100	767
Net income available to common shareholders	**$ 1,277,477**	$ 1,150,603	$ 387,074
Basic earnings per common share (Note I)	**$ 3.09**	$ 2.80	$ 1.30
Diluted earnings per common share (Note I)	**$ 3.07**	$ 2.78	$ 1.29
Average shares *(thousands)*			
Basic	**413,560**	411,485	297,477
Diluted	**415,444**	414,195	299,780

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2019	**2018**	**2017**
	(*Thousands of dollars*)		
Net income	**$ 1,278,577**	$ 1,155,032	$ 593,519
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives, net of tax of $44,149, $1,694 and $19,006, respectively	**(147,803)**	(5,673)	(21,408)
Derivative amounts reclassified to net income, net of tax of $6,058, $(11,013) and $(26,899), respectively	**(21,057)**	36,870	63,687
Change in retirement and other postretirement benefit plan obligations, net of tax of $2,910, $(1,425) and $(878), respectively	**(9,696)**	4,771	(4,175)
Other comprehensive income (loss) of unconsolidated affiliates, net of tax of $2,152, $(724) and $145, respectively	**(7,205)**	2,424	(970)
Total other comprehensive income (loss), net of tax	**(185,761)**	38,392	37,134
Comprehensive income	**1,092,816**	1,193,424	630,653
Less: Comprehensive income attributable to noncontrolling interests	**—**	3,329	236,704
Comprehensive income attributable to ONEOK	**$ 1,092,816**	$ 1,190,095	$ 393,949

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
Assets	*(Thousands of dollars)*	
Current assets		
Cash and cash equivalents	**$ 20,958**	$ 11,975
Accounts receivable, net	**835,121**	818,958
Materials and supplies	**201,749**	141,174
Natural gas and NGLs in storage	**304,926**	296,667
Commodity imbalances	**25,267**	29,050
Other current assets	**82,313**	100,808
Total current assets	**1,470,334**	1,398,632
Property, plant and equipment		
Property, plant and equipment	**22,051,492**	18,030,963
Accumulated depreciation and amortization	**3,702,807**	3,264,312
Net property, plant and equipment (Note D)	**18,348,685**	14,766,651
Investments and other assets		
Investments in unconsolidated affiliates (Note M)	**861,844**	969,150
Goodwill and intangible assets (Note E)	**957,833**	967,142
Other assets	**173,425**	130,096
Total investments and other assets	**1,993,102**	2,066,388
Total assets	**$ 21,812,121**	$ 18,231,671

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31, 2019	December 31, 2018
Liabilities and equity	(*Thousands of dollars*)	
Current liabilities		
Current maturities of long-term debt (Note F)	**$ 7,650**	$ 507,650
Short-term borrowings (Note F)	**220,000**	—
Accounts payable	**1,209,900**	1,116,337
Commodity imbalances	**104,480**	110,197
Accrued interest	**190,750**	161,377
Finance lease liability (Note O)	**1,949**	1,765
Other current liabilities	**285,569**	211,110
Total current liabilities	**2,020,298**	2,108,436
Long-term debt, excluding current maturities (Note F)	**12,479,757**	8,873,334
Deferred credits and other liabilities		
Deferred income taxes (Note L)	**536,063**	219,731
Finance lease liability (Note O)	**24,296**	26,244
Other deferred credits	**525,756**	424,383
Total deferred credits and other liabilities	**1,086,115**	670,358
Commitments and contingencies (Note N)		
Equity (Note G)		
ONEOK shareholders' equity:		
Preferred stock, $0.01 par value: authorized and issued 20,000 shares at December 31, 2019, and at December 31, 2018	**—**	—
Common stock, $0.01 par value: authorized 1,200,000,000 shares; issued 445,016,234 shares and outstanding 413,239,050 shares at December 31, 2019; issued 445,016,234 shares and outstanding 411,532,606 shares at December 31, 2018	**4,450**	4,450
Paid-in capital	**7,403,895**	7,615,138
Accumulated other comprehensive loss (Note H)	**(374,000)**	(188,239)
Retained earnings	**—**	—
Treasury stock, at cost: 31,777,184 shares at December 31, 2019, and 33,483,628 shares at December 31, 2018	**(808,394)**	(851,806)
Total equity	**6,225,951**	6,579,543
Total liabilities and equity	**$ 21,812,121**	$ 18,231,671

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2019	**2018**	**2017**
	(Thousands of dollars)		
Operating activities			
Net income	**$ 1,278,577**	$ 1,155,032	$ 593,519
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**476,535**	428,557	406,335
Impairment charges	**—**	—	20,240
Noncash contribution of preferred stock, net of tax	**—**	—	12,600
Equity in net earnings from investments	**(154,541)**	(158,383)	(159,278)
Distributions received from unconsolidated affiliates	**163,476**	170,528	167,372
Deferred income taxes	**372,729**	361,010	437,917
Share-based compensation expense	**37,147**	31,664	26,262
Allowance for equity funds used during construction	**(64,815)**	(7,962)	(107)
Other, net	**1,567**	(132)	3,155
Changes in assets and liabilities:			
Accounts receivable	**(19,688)**	383,993	(330,521)
Natural gas and NGLs in storage	**(8,259)**	38,456	(202,259)
Accounts payable	**(62,946)**	(320,132)	261,305
Commodity imbalances, net	**(1,934)**	(44,302)	43,699
Accrued interest	**29,373**	26,068	22,795
Risk-management assets and liabilities	**(86,268)**	117,717	37,617
Other assets and liabilities, net	**(14,174)**	4,605	(25,239)
Cash provided by operating activities	**1,946,779**	2,186,719	1,315,412
Investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(3,848,349)**	(2,141,475)	(512,393)
Contributions to unconsolidated affiliates	**(4,028)**	(1,748)	(87,861)
Distributions received from unconsolidated affiliates in excess of cumulative earnings	**94,168**	26,757	28,742
Other, net	**(10,549)**	1,578	3,879
Cash used in investing activities	**(3,768,758)**	(2,114,888)	(567,633)
Financing activities			
Dividends paid	**(1,457,628)**	(1,335,058)	(829,414)
Distributions to noncontrolling interests	**—**	(3,500)	(276,260)
Borrowing (repayment) of short-term borrowings, net	**220,000**	(614,673)	(495,604)
Issuance of long-term debt, net of discounts	**4,185,435**	1,795,773	1,190,496
Debt financing costs	**(29,747)**	(13,441)	(11,425)
Repayment of long-term debt	**(1,057,348)**	(932,650)	(994,776)
Issuance of common stock	**29,040**	1,203,981	471,358
Acquisition of noncontrolling interests	**—**	(195,000)	—
Other, net	**(58,790)**	(2,481)	(13,836)
Cash provided by (used in) financing activities	**1,830,962**	(97,049)	(959,461)
Change in cash and cash equivalents	**8,983**	(25,218)	(211,682)
Cash and cash equivalents at beginning of period	**11,975**	37,193	248,875
Cash and cash equivalents at end of period	**$ 20,958**	$ 11,975	$ 37,193
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 435,165**	$ 418,244	$ 432,210
Cash paid for income taxes, net of refunds	**$ 2,690**	$ 2,225	$ 6,633

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, 2017	245,811,180	—	$ 2,458	$ —	$ 1,234,314
Cumulative effect adjustment for adoption of ASU 2016-09 (a)	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss)	—	—	—	—	—
Preferred stock issued	—	20,000	—	—	20,000
Preferred stock dividends - $38.35 per share (Note G)	—		—	—	(767)
Common stock issued	8,434,223	—	85	—	456,537
Common stock dividends - $2.72 per share (Note G)	—	—	—	—	(367,578)
Distributions to noncontrolling interests	—	—	—	—	—
Acquisition of noncontrolling interests (Note G)	168,920,831	—	1,689	—	5,228,580
Other, net	—	—	—	—	17,792
December 31, 2017	423,166,234	20,000	4,232	—	6,588,878
Cumulative effect adjustment for adoption of ASUs (b)	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note H)	—	—	—	—	—
Preferred stock dividends - $55.00 per share (Note G)	—	—	—	—	—
Common stock issued	21,850,000	—	218	—	1,183,321
Common stock dividends - $3.245 per share (Note G)	—	—	—	—	(144,805)
Distributions to noncontrolling interests	—	—	—	—	—
Contributions from noncontrolling interests	—	—	—	—	—
Acquisition of noncontrolling interests (Note G)	—	—	—	—	(21,220)
Other, net	—	—	—	—	8,964
December 31, 2018	445,016,234	20,000	4,450	—	7,615,138
Cumulative effect adjustment for adoption of ASU 2016-02 (Note A)	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note H)	—	—	—	—	—
Preferred stock dividends - $55.00 per share (Note G)	—	—	—	—	—
Common stock issued	—	—	—	—	**(7,667)**
Common stock dividends - $3.53 per share (Note G)	—	—	—	—	**(180,421)**
Other, net	—	—	—	—	**(23,155)**
December 31, 2019	**445,016,234**	**20,000**	**$ 4,450**	**$ —**	**$ 7,403,895**

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, 2017	$ (154,350)	$ —	$ (893,677)	$ 3,240,170	$ 3,428,915
Cumulative effect adjustment for adoption of ASU 2016-09 (a)	—	73,368	—	—	73,368
Net income	—	387,841	—	205,678	593,519
Other comprehensive income (loss)	6,108	—	—	31,026	37,134
Preferred stock issued	—	—	—	—	20,000
Preferred stock dividends - $38.35 per share (Note G)	—	—	—	—	(767)
Common stock issued	—	—	16,964	—	473,586
Common stock dividends - $2.72 per share (Note G)	—	(461,209)	—	—	(828,787)
Distributions to noncontrolling interests	—	—	—	(276,260)	(276,260)
Acquisition of noncontrolling interests (Note G)	(40,288)	—	—	(3,043,519)	2,146,462
Other, net	—	—	—	390	18,182
December 31, 2017	(188,530)	—	(876,713)	157,485	5,685,352
Cumulative effect adjustment for adoption of ASUs (b)	(38,101)	39,803	—	17	1,719
Net income	—	1,151,703	—	3,329	1,155,032
Other comprehensive income (loss) (Note H)	38,392	—	—	—	38,392
Preferred stock dividends - $55.00 per share (Note G)	—	(1,100)	—	—	(1,100)
Common stock issued	—	—	24,907	—	1,208,446
Common stock dividends - $3.245 per share (Note G)	—	(1,190,406)	—	—	(1,335,211)
Distributions to noncontrolling interests	—	—	—	(3,500)	(3,500)
Contributions from noncontrolling interests	—	—	—	16,449	16,449
Acquisition of noncontrolling interests (Note G)	—	—	—	(173,780)	(195,000)
Other, net	—	—	—	—	8,964
December 31, 2018	(188,239)	—	(851,806)	—	6,579,543
Cumulative effect adjustment for adoption of ASU 2016-02 (Note A)	**—**	**(67)**	**—**	**—**	**(67)**
Net income	**—**	**1,278,577**	**—**	**—**	**1,278,577**
Other comprehensive income (loss) (Note H)	**(185,761)**	**—**	**—**	**—**	**(185,761)**
Preferred stock dividends - $55.00 per share (Note G)	**—**	**(1,100)**	**—**	**—**	**(1,100)**
Common stock issued	**—**	**—**	**43,412**	**—**	**35,745**
Common stock dividends - $3.53 per share (Note G)	**—**	**(1,277,410)**	**—**	**—**	**(1,457,831)**
Other, net	**—**	**—**	**—**	**—**	**(23,155)**
December 31, 2019	**$ (374,000)**	**$ —**	**$ (808,394)**	**$ —**	**$ 6,225,951**

(a) - Includes adjustment increasing beginning retained earnings 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.
(b) - Includes cumulative effect for adoption of the following: ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)"; ASU 2017-12, "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities"; and ASU 2018-02, "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income."

See accompanying Notes to Consolidated Financial Statements.

ONEOK, INC. AND SUBSIDIARIES
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.

Our Natural Gas Gathering and Processing segment provides midstream services to 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. 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 NGLs separated from the raw natural gas are delivered through NGL pipelines to fractionation facilities for further processing.

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, Powder River and DJ Basins. 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. The majority of the pipeline-connected natural gas processing plants in the Williston Basin, Oklahoma, Kansas and the Texas Panhandle are connected to our NGL gathering systems. We own or have an ownership interest in FERC-regulated NGL 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 NGL 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.

Our Natural Gas Pipelines segment provides interstate and intrastate transportation and storage services to end users through its wholly owned assets and its 50% ownership interests in Northern Border Pipeline and Roadrunner. 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 intrastate natural gas pipeline and storage assets are located in Oklahoma, Kansas and Texas. Our assets connect major natural gas producing basins and market hubs with end-use customers.

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 M 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 prices and estimated volumes. The estimates are reversed in the following month and recorded with actual volumes and prices.

We evaluate our 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 - For our fair value measurements, we utilize market prices, third-party pricing services, present value methods and standard option valuation models to determine the price we would receive from the sale of an asset or the transfer of a liability in an orderly transaction at the measurement date. 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.

Many of the contracts in our derivative portfolio are executed in liquid markets where price transparency exists. Our financial commodity derivatives are generally settled through a NYMEX or Intercontinental Exchange (ICE) clearing broker account with daily margin requirements. We validate our valuation inputs with third-party information and settlement prices from other sources, where available.

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 the implied forward LIBOR yield curve. 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. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using counterparty-specific bond yields. 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 materially from our estimates.

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. These balances are composed predominantly of exchange-traded derivative contracts for natural gas and crude oil.
- Level 2 - fair value measurements are based on significant observable pricing inputs, including quoted prices for similar assets and liabilities in active markets and inputs from third-party pricing services supported with corroborative evidence. These balances are composed of over-the-counter interest-rate derivatives.
- Level 3 - fair value measurements are based on inputs that may include one or more unobservable inputs, including internally developed commodity price curves that incorporate market data from broker quotes and third-party pricing services. These balances are composed predominantly of exchange-cleared and over-the-counter derivatives to hedge NGL price risk and natural gas basis risk between various transaction locations and the NYMEX Henry Hub. Our commodity derivatives are generally valued using forward quotes provided by third-party pricing services that are validated with other market data. We believe any measurement uncertainty at December 31, 2019, is immaterial as our Level 3 fair value measurements are based on unadjusted pricing information from broker quotes and third-party pricing services. We do not believe that our Level 3 fair value estimates have a material impact on our results of operations, as our derivatives are accounted for as hedges.

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 B for our fair value measurements disclosures.

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 - Revenues are recognized when control of the promised goods or services is transferred to our customers in an amount that reflects the consideration we expect to be entitled to receive in exchange for those goods or services. Our payment terms vary by customer and contract type, including requiring payment before products or services are delivered to certain customers. However, the term between customer prepayments, completion of our performance obligations, invoicing and receipt of payment due is not significant.

A significant portion of supply volumes in our Natural Gas Gathering and Processing and Natural Gas Liquids segments are under contracts that include the purchase of commodities. Therefore, upon adoption of Topic 606, the contractual fees we charge on these contracts are considered a reduction of the commodity purchase price in cost of sales and fuel. In 2017 and prior periods, we recorded these fees as services revenue. See "Cost of Sales and Fuel" below for a description of these arrangements.

Performance Obligations and Revenue Sources - Revenues sources are disaggregated in Note Q and are derived from commodity sales and services revenues, as described below:

Commodity Sales (all segments) - We contract to deliver residue natural gas, condensate, unfractionated NGLs and/or NGL products to customers at a specified delivery point. Our sales agreements may be daily or longer-term contracts for a specified volume. We consider the sale and delivery of each unit of a commodity an individual performance obligation as the customer is expected to control, accept and benefit from each unit individually. We record revenue when the commodity is delivered to the customer as this represents the point in time when control of the product is transferred to the customer. Revenue is recorded based on the contracted selling price, which is generally index-based and settled monthly.

Services

Gathering only contracts (*Natural Gas Gathering and Processing segment*) - Under this type of contract, we charge fees for providing midstream services, which include gathering and treating our customer's natural gas. Our performance obligation begins with delivery of raw natural gas to our system. This service is treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously.

POP with fee contracts with producer take-in-kind rights (*Natural Gas Gathering and Processing segment*) - Under this type of contract, we do not control the stream of unprocessed natural gas that we receive at the wellhead due to the producer's take-in-kind rights. We purchase a portion of the raw natural gas stream, charge fees for providing midstream services, which include gathering, treating, compressing and processing our customer's natural gas. After performing these services, we return primarily the residue natural gas to the producer, sell the remaining commodities and remit a portion of the commodity sales proceeds to the producer less our contractual fees. Our performance obligation begins with delivery of raw natural gas to our system. This service is treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously.

Transportation and exchange contracts (*Natural Gas Liquids segment*) - Under this type of contract, we charge fees for providing midstream services, which may include a bundled combination of gathering, transporting and/or fractionation of our customer's NGLs. Our performance obligation begins with delivery of unfractionated NGLs or NGL products to our system. These services represent a series of distinct services that are treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously. For transportation services under a tariff on our NGL transportation pipelines, fees are recorded upon redelivery to our customer at the completion of the transportation services.

Storage contracts (*Natural Gas Liquids and Natural Gas Pipelines segments*) - We reserve a stated storage capacity and inject/withdraw/store commodities for our customer. The capacity reservation and injection/withdrawal/storage services are considered a bundled service, as we integrate them into one stand-ready obligation provided on a daily basis over the life of the agreement and satisfied over time. Fixed capacity reservation fees are allocated and evenly recognized in revenue. Capacity reservation fees that vary based on a stated or implied economic index and correspond with the costs to provide our services are recognized in revenue as invoiced to our customers. For contracts that do not include a capacity reservation, transportation, injection and withdrawal fees are recognized in revenue as those services are provided and are dependent on the volume transported, injected or withdrawn by our customer, which is at our customer's discretion. We use the output method based on the passage of time to measure satisfaction of the performance obligation associated with our daily stand-ready services.

Firm service transportation contracts (*Natural Gas Pipelines segment*) - We reserve a stated transportation capacity and transport commodities for our customer. The capacity reservation and transportation services are considered a bundled service, as we integrate them into one stand-ready obligation provided on a daily basis over the life of the agreement and satisfied over time. Fixed capacity reservation fees are allocated and evenly recognized in revenue. Capacity reservation fees that vary based on a stated or implied economic index and correspond with the costs to provide our services are recognized in revenue based on a daily effective fee rate. If the capacity reservation fees vary solely as a contract feature, contract assets or liabilities are recorded for the difference between the amount recorded in revenue and the amount billed to the customer. Transportation fees are recognized in revenue as those services are provided and are dependent on the volume transported by our customer, which is at our customer's discretion. We use the output method based on the passage of time to measure satisfaction of the performance obligation associated with our daily stand-ready services.

Interruptible transportation contracts (*Natural Gas Pipelines segment*) - We agree to transport natural gas on our pipelines between the customer's specified nomination and delivery points if capacity is available after satisfying firm transportation service obligations. The transaction price is based on the transportation fees times the volumes transported. These fees may change over time based on an index or other factors provided in the agreement. We use the output method based on delivery of product to the customer to measure satisfaction of the performance obligation. The total consideration for delivered volumes is recorded in revenue at the time of delivery, when the customer obtains control.

See Note P for our revenue disclosures.

Contract Assets and Contract Liabilities - Contract assets and contract liabilities are recorded when the amount of revenue recognized from a contract with a customer differs from the amount billed to the customer and recorded in accounts receivable. Our contract asset balances at the beginning and end of the period primarily relate to our firm service transportation contracts with tiered rates. Our contract liabilities primarily represent deferred revenue on contributions in aid of construction received from customers for which revenue is recognized over the contract periods, which range from 5 to 10 years, and deferred revenue on NGL storage contracts for which revenue is recognized over a one-year term.

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, (iii) fuel and power costs incurred to operate our own facilities that gather, process, transport and store commodities, and (iv) an offset from the contractual fees deducted from the cost of purchased commodities under the contract types below:

POP with fee contracts with no producer take-in-kind rights (Natural Gas Gathering and Processing segment) - We purchase raw natural gas and charge contractual fees for providing midstream services, which include gathering, treating, compressing and processing the producer's natural gas. After performing these services, we sell the commodities and return a portion of the commodity sales proceeds to the producer less our contractual fees.

Purchase with fee (*Natural Gas Liquids segment*) - Under this type of contract, we purchase raw, unfractionated NGLs at an index price and charge fees for providing midstream services, which may include a bundled combination of gathering, transporting and/or fractionation of our customer's NGLs.

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, 2019 and 2018, our allowance for doubtful accounts was not material.

Update - Upon adoption of ASU 2016-13 in January 2020, we are required to present accounts receivable net of an allowance for credit losses to reflect the net amount expected to be collected. This assessment is based on historical information, current conditions and supportable forecasts. See "Recently Issued Accounting Standards Update" table below for more information.

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, transportation and fractionation 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 generally 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	- The gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	- 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 effectiveness. 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 at inception of the hedge by performing an effectiveness analysis on our fair value and cash flow hedging relationships to determine whether the hedge relationships are highly effective. Subsequently we perform qualitative assessments. 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, options 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 B and C for disclosures of our fair value measurements and risk-management and hedging activities.

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 approved. 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 D for our property, plant and equipment disclosures.

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, 2019, 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.

Update - Upon adoption of ASU 2017-04 in January 2020, the requirement to calculate the implied fair value of goodwill under the two-step impairment test was eliminated. See "Recently Issued Accounting Standards Update" table below for more information.

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 D, E and M for our long-lived assets, goodwill and intangible assets and investments in unconsolidated affiliates disclosures.

Regulation - Depending on the specific service provided, our natural gas transmission pipelines, NGL pipelines and certain natural gas storage facilities are subject to rate regulation and/or accounting requirements by one or more of the FERC, OCC, KCC and RRC. 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 amounts we may charge our customers. 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 (i) established by independent, third-party regulators and (ii) set at levels that will recover our costs when considering the demand and competition for our services.

Retirement and Other 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 changes in the costs and liabilities we recognize.

See Note K for our retirement and other postretirement employee benefits disclosures.

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.

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 2019, 2018 and 2017, we had no uncertain tax positions that required the 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 L for our income taxes disclosures.

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, NGL 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 NGLs exist. 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 NGLs 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.

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 2019, 2018 and 2017. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note N 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.

See Note J for our share-based payments disclosures.

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.

See Note I for our earnings per share disclosures.

Segment Reporting - 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. 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 expense, and other noncash items. This calculation may not be comparable with similarly titled measures of other companies.

See Note Q for our segments disclosures.

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

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 previously issued or 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 as of December 31, 2019			
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 adopted this standard on January 1, 2019, using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative adjustment to equity. On January 1, 2019, we recorded an immaterial cumulative effect for the adoption of the new standard and recorded $17.5 million of right-of-use assets and $17.4 million of lease liabilities related to operating leases that were not previously recorded on our Consolidated Balance Sheets. Our finance lease assets and liabilities at January 1, 2019, of $28.1 million and $28.0 million, respectively, did not change as a result of adopting this standard. See Note O for additional disclosures.
ASU 2018-07, "Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting"	The standard aligns the measurement and classification guidance for share-based payments to nonemployees with the guidance for share-based payments to employees, with certain exceptions.	First quarter 2019	The impact of adopting this standard was not material.
Standards that are not yet adopted as of December 31, 2019			
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 adopted this standard in January 2020, and the impact of adopting this standard was not material.
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 adopted this standard in January 2020, and the impact of adopting this standard was not material.
ASU 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes"	The standard simplifies certain concepts in Topic 740, Income Taxes.	First quarter 2021	We do not expect the adoption of this standard to materially impact us.

B. FAIR VALUE MEASUREMENTS

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

	December 31, 2019					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net
	(*Thousands of dollars*)					
Derivative assets						
Commodity contracts						
Financial contracts	**$ 10,892**	**$ —**	**$ 55,557**	**$ 66,449**	**$ (28,588)**	**$ 37,861**
Interest-rate contracts	**—**	**581**	**—**	**581**	**—**	**581**
Total derivative assets	**$ 10,892**	**$ 581**	**$ 55,557**	**$ 67,030**	**$ (28,588)**	**$ 38,442**
Derivative liabilities						
Commodity contracts						
Financial contracts	**$ (4,811)**	**$ —**	**$ (24,785)**	**$ (29,596)**	**$ 28,588**	**$ (1,008)**
Interest-rate contracts	**—**	**(201,941)**	**—**	**(201,941)**	**—**	**(201,941)**
Total derivative liabilities	**$ (4,811)**	**$ (201,941)**	**$ (24,785)**	**$ (231,537)**	**$ 28,588**	**$ (202,949)**

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheet 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, 2019, we held no cash and posted $8.8 million of cash with various counterparties, which is included in other current assets in our Consolidated Balance Sheet.

	December 31, 2018					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net
	(*Thousands of dollars*)					
Derivative assets						
Commodity contracts						
Financial contracts	$ 10,812	$ —	$ 69,165	$ 79,977	$ (32,739)	$ 47,238
Physical contracts	—	—	1,142	1,142	—	1,142
Interest-rate contracts	—	19,005	—	19,005	—	19,005
Total derivative assets	$ 10,812	$ 19,005	$ 70,307	$ 100,124	$ (32,739)	$ 67,385
Derivative liabilities						
Commodity contracts						
Financial contracts	$ (2,916)	$ —	$ (29,823)	$ (32,739)	$ 32,739	$ —
Interest-rate contracts	—	(99,260)	—	(99,260)	—	(99,260)
Total derivative liabilities	$ (2,916)	$ (99,260)	$ (29,823)	$ (131,999)	$ 32,739	$ (99,260)

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheet 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, 2018, we held no cash and posted $0.8 million of cash with various counterparties, which is included in other current assets in our Consolidated Balance Sheet.

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

Derivative Assets (Liabilities)	Years Ended December 31, 2019	2018
	(*Thousands of dollars*)	
Net assets (liabilities) at beginning of period	**$ 40,484**	$ (32,838)
Total changes in fair value:		
Gains (losses) included in net income (a)	**—**	(140)
Settlements included in net income (a)	**(40,344)**	29,141
New Level 3 derivatives included in other comprehensive income (loss) (b)	**30,627**	37,106
Unrealized change included in other comprehensive income (loss) (b)	**5**	7,215
Net assets (liabilities) at end of period	**$ 30,772**	$ 40,484

(a) - Included in commodity sales revenues/cost of sales and fuel in our Consolidated Statements of Income.
(b) - Included in change in fair value of derivatives in our Consolidated Statements of Comprehensive Income.

During the years ended December 31, 2019 and 2018, there were no transfers in or out of Level 3 of the fair value hierarchy.

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 composed 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 $13.8 billion and $9.6 billion at December 31, 2019 and 2018, respectively. The book value of our consolidated long-term debt, including current maturities, was $12.5 billion and $9.4 billion at December 31, 2019 and 2018, respectively. The estimated fair value of the aggregate 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.

C. 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 may 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 primarily exposed to commodity price risk resulting from the relative values of the various NGL products to each other, the value of NGLs in storage and the relative value of NGLs to natural gas. We are also exposed to location price differential risk as a result of the relative value of NGL purchases at one location and sales at another location, primarily related to our optimization and marketing business. As part of our hedging strategy, 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 pipelines consume natural gas in operations and retain natural gas from our customers for operations or as part of our fee for services provided. When the amount consumed in operations 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 natural gas price fluctuations. At December 31, 2019 and 2018, 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 2019, we entered into $625 million of forward-starting interest-rate swaps 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. We also settled $1.8 billion of our forward-starting interest-rate swaps related to our underwritten public offering of $1.25 billion senior unsecured notes in March 2019 and $2.0 billion senior unsecured notes in August 2019.

At December 31, 2019 and 2018, we had forward-starting interest-rate swaps with notional amounts totaling $1.8 billion and $3.0 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances. At December 31, 2019 and 2018, we had interest-rate swaps with notional amounts totaling $1.3 billion to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges.

Fair Values of Derivative Instruments - All derivatives measured at fair value at December 31, 2019 and 2018, were designated as hedging instruments. See Note B for a discussion of the inputs associated with our fair value measurements. The following table sets forth the fair values of our derivative instruments presented on a gross basis for the periods indicated:

		December 31, 2019		December 31, 2018	
	Location in our Consolidated Balance Sheets	**Assets**	**(Liabilities)**	**Assets**	**(Liabilities)**
			(*Thousands of dollars*)		
Derivatives designated as hedging instruments					
Commodity contracts (a)					
Financial contracts	Other current assets	**$ 64,858**	**$ (26,997)**	$ 78,891	$ (31,793)
	Other assets/other deferred credits	**1,591**	**(2,599)**	1,086	(946)
Physical contracts	Other current assets	**—**	**—**	1,142	—
Interest-rate contracts	Other current assets/other current liabilities	**—**	**(90,161)**	19,005	(15,012)
	Other assets/other deferred credits	**581**	**(111,780)**	—	(84,248)
Total derivatives designated as hedging instruments		**$ 67,030**	**$ (231,537)**	$ 100,124	$ (131,999)

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us.

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, 2019 Purchased/ Payor	December 31, 2019 Sold/ Receiver	December 31, 2018 Purchased/ Payor	December 31, 2018 Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(59.0)**	—	(29.9)
-Crude oil and NGLs (*MMBbl*)	Futures, forwards and swaps	**7.9**	**(17.4)**	6.5	(13.8)
Basis					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(59.0)**	—	(29.9)
Interest-rate contracts (*Billions of dollars*)	Swaps	**$ 3.1**	**$ —**	$ 4.3	$ —

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 - The following table sets forth the unrealized change in fair value of cash flow hedges in other comprehensive income (loss) for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	**2019**	**2018**	**2017**
		(*Thousands of dollars*)	
Commodity contracts	**$ 38,819**	$ 53,217	$ (40,577)
Interest-rate contracts	**(230,771)**	(60,584)	163
Total unrealized change in fair value of cash flow hedges in other comprehensive income (loss)	**$ (191,952)**	$ (7,367)	$ (40,414)

The following table sets forth the effect of cash flow hedges on net income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	**Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income**	**2019**	**2018**	**2017**
			(*Thousands of dollars*)	
Commodity contracts	Commodity sales revenues/cost of sales and fuel	**$ 50,345**	$ (29,596)	$ (69,561)
Interest-rate contracts	Interest expense	**(23,230)**	(18,287)	(21,025)
Total change in fair value of cash flow hedges reclassified from accumulated other comprehensive loss into net income on derivatives		**$ 27,115**	$ (47,883)	$ (90,586)

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 use internally developed credit ratings for counterparties that do not have a credit rating.

Our financial commodity derivatives are generally settled through a NYMEX or Intercontinental Exchange (ICE) clearing broker account with daily margin requirements. However, 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, 2019.

The counterparties to our derivative contracts typically consist 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, 2019, the net credit exposure from our derivative assets is with investment-grade companies in the financial services sector.

D. 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, 2019	December 31, 2018
		(*Thousands of dollars*)	
Nonregulated			
Gathering pipelines and related equipment	5 to 40	**$ 4,316,936**	$ 3,851,043
Processing and fractionation and related equipment	3 to 40	**4,439,332**	4,171,072
Storage and related equipment	3 to 54	**684,635**	656,455
Transmission pipelines and related equipment	5 to 54	**797,678**	782,258
General plant and other	2 to 60	**610,013**	547,424
Construction work in process	—	**1,645,663**	797,182
Regulated			
Storage and related equipment	5 to 25	**9,180**	8,987
Natural gas transmission pipelines and related equipment	5 to 77	**1,552,546**	1,475,789
NGL transmission pipelines and related equipment	5 to 88	**6,126,056**	4,677,599
General plant and other	2 to 50	**66,507**	61,136
Construction work in process	—	**1,802,946**	1,002,018
Property, plant and equipment		**22,051,492**	18,030,963
Accumulated depreciation and amortization - nonregulated		**(2,471,649)**	(2,168,855)
Accumulated depreciation and amortization - regulated		**(1,231,158)**	(1,095,457)
Net property, plant and equipment		**$ 18,348,685**	$ 14,766,651

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,		
	2019	2018	2017
Natural Gas Liquids	**2.0%**	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, 2019, 2018 and 2017, of $544.8 million, $388.3 million and $92.4 million, respectively. Such amounts are not included in capital expenditures (less AFUDC and capitalized interest) on the Consolidated Statements of Cash Flows.

Impairment Charges - In 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.

E. GOODWILL AND INTANGIBLE ASSETS

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

	December 31, 2019	December 31, 2018
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 153,404**	$ 153,404
Natural Gas Liquids	**371,217**	371,217
Natural Gas Pipelines	**156,375**	156,479
Total goodwill	**$ 680,996**	$ 681,100

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 15 to 40 years. Amortization expense for intangible assets was $11.9 million in 2019, 2018 and 2017, and the aggregate amortization expense for each of the next five years is estimated to be $11.9 million. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2019	December 31, 2018
	(Thousands of dollars)	
Gross intangible assets	**$ 414,345**	$ 411,650
Accumulated amortization	**(137,508)**	(125,608)
Net intangible assets	**$ 276,837**	$ 286,042

F. DEBT

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

	December 31, 2019	December 31, 2018
	(Thousands of dollars)	
Commercial paper outstanding, bearing a weighted-average interest rate of 2.16% as of December 31, 2019	**$ 220,000**	$ —
Senior unsecured obligations:		
$500,000 at 8.625% due March 2019	—	500,000
$300,000 at 3.8% due March 2020	—	300,000
$1,500,000 term loan, rate of 2.70% and 3.63% as of December 31, 2019 and 2018, respectively, due November 2021	**1,250,000**	550,000
$700,000 at 4.25% due February 2022	**547,397**	547,397
$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 7.5% due September 2023	**500,000**	500,000
$500,000 at 2.75% due September 2024	**500,000**	—
$500,000 at 4.9 % due March 2025	**500,000**	500,000
$500,000 at 4.0% due July 2027	**500,000**	500,000
$800,000 at 4.55% due July 2028	**800,000**	800,000
$100,000 at 6.875% due September 2028	**100,000**	100,000
$700,000 at 4.35% due March 2029	**700,000**	—
$750,000 at 3.4% due September 2029	**750,000**	—
$400,000 at 6.0% due June 2035	**400,000**	400,000
$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
$700,000 at 4.95% due July 2047	**700,000**	700,000
$1,000,000 at 5.2% due July 2048	**1,000,000**	450,000
$750,000 at 4.45% due September 2049	**750,000**	—
Guardian Pipeline		
Weighted average 7.85% due December 2022	**21,307**	28,957
Total debt	**12,813,704**	9,451,354
Unamortized portion of terminated swaps	**15,032**	16,750
Unamortized debt issuance costs and discounts	**(121,329)**	(87,120)
Current maturities of long-term debt	**(7,650)**	(507,650)
Short-term borrowings (a)	**(220,000)**	—
Long-term debt	**$ 12,479,757**	$ 8,873,334

(a) - Individual issuances of commercial paper under our commercial paper program generally mature in 90 days or less.

$2.5 Billion Credit Agreement - In May 2019, we extended the term of our $2.5 Billion Credit Agreement by one year to June 2024. Our $2.5 Billion Credit Agreement is a 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 5.0 to 1 at December 31, 2019. 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 following two quarters. Thereafter, the covenant will decrease to 5.0 to 1.

Our $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 our $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. Our $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. At December 31, 2019, our ratio of indebtedness to adjusted EBITDA was 4.1 to 1, and we were in compliance with all covenants under our $2.5 Billion Credit Agreement.

At December 31, 2019 and 2018, we had letters of credit issued totaling $4.7 million and $1.4 million, respectively, and no borrowings outstanding under our $2.5 Billion 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 August 2019, we completed an underwritten public offering of $2.0 billion senior unsecured notes consisting of $500 million, 2.75% senior notes due 2024; $750 million, 3.4% senior notes due 2029; and $750 million, 4.45% senior notes due 2049. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $1.97 billion. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

In March 2019, we completed an underwritten public offering of $1.25 billion senior unsecured notes consisting of $700 million, 4.35% senior notes due 2029 and an additional issuance of $550 million of our existing 5.2% senior notes due 2048. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, and exclusive of accrued interest, were $1.23 billion. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

In November 2018, we entered into our $1.5 Billion Term Loan Agreement with a syndicate of banks, which was fully drawn as of June 30, 2019. We repaid $250 million of our outstanding balance in August 2019 and have $1.25 billion drawn as of December 31, 2019. Our $1.5 Billion Term Loan Agreement matures in November 2021 and bears interest at LIBOR plus 112.5 basis points based on our current credit ratings. The agreement contains an option, which may be exercised up to two times, to extend the term of the loan, in each case, for an additional one-year term subject to approval of the banks. Our $1.5 Billion Term Loan Agreement allows prepayment of all or any portion outstanding, without penalty or premium, and contains substantially the same covenants as those contained in our $2.5 Billion Credit Agreement. The proceeds were used for general corporate purposes, including repayment of existing indebtedness and funding capital expenditures.

In July 2018, we completed an underwritten public offering of $1.25 billion senior unsecured notes consisting of $800 million, 4.55% senior notes due 2028 and $450 million, 5.2% senior notes due 2048. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were $1.23 billion. The proceeds were used for general corporate purposes, which included repayment of existing indebtedness and funding capital expenditures.

In July 2017, we completed an underwritten public offering of $1.2 billion senior unsecured notes consisting of $500 million, 4.0% senior notes due 2027, and $700 million, 4.95% 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 funding capital expenditures.

Repayments - In September 2019, we redeemed our $300 million, 3.8% senior notes due March 2020 at a redemption price of $308.0 million, including the outstanding principal, plus accrued and unpaid interest, with cash on hand from our public offering of $2.0 billion senior unsecured notes in August 2019. In connection with this early redemption, we incurred a $2.7

million loss on extinguishment of debt, which is included in other expense in our Consolidated Statements of Income for the year ended December 31, 2019.

In August 2019, we repaid $250 million of our $1.5 Billion Term Loan agreement with cash on hand.

In March 2019, we repaid our $500 million, 8.625% senior notes at maturity with a combination of cash on hand and short-term borrowings.

In 2018, we repaid our $425 million, 3.2% senior notes due September 2018 with cash on hand and the remaining $500 million of the ONEOK Partners Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings.

In 2017, we repaid ONEOK Partners' $400 million, 2.0% senior notes due in October 2017 and repaid $500 million of the ONEOK Partners Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings and redeemed our 6.5% senior notes due 2028 at a redemption price of $87.0 million with cash on hand.

The aggregate maturities of long-term debt outstanding as of December 31, 2019, for the years 2020 through 2024 are shown below:

	Senior Unsecured Obligations	Guardian Pipeline	Total
		(Millions of dollars)	
2020	$ —	$ 7.7	$ 7.7
2021	$ 1,250.0	$ 7.7	$ 1,257.7
2022	$ 1,447.4	$ 5.9	$ 1,453.3
2023	$ 925.0	$ —	$ 925.0
2024	$ 500.0	$ —	$ 500.0

<u>Covenants</u> - Our senior notes are governed by indentures containing covenants, including among other provisions, limitations on our ability to place liens on our property or assets and to sell and leaseback our property. The indentures governing our 6.875% senior notes due 2028 include an event of default upon acceleration of other indebtedness of $15 million or more, and the indentures governing the remainder of our senior notes 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% in aggregate principal amount of the outstanding senior notes to declare those senior notes immediately due and payable in full. The indenture for the 7.5% 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% of the principal amount, plus accrued and unpaid interest, if any.

We may redeem our 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. We may redeem the balance of our senior notes due 2022, 2023, 2024, 2025, 2027, 2028 (4.55%), 2029, 2041, 2043, 2047, 2048 and 2049 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting one to six months before the maturity date as stipulated in the respective contract terms. Our senior notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

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, 2019, 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.

Debt Guarantees - ONEOK, ONEOK Partners and the Intermediate Partnership have cross guarantees in place for our and ONEOK Partners' indebtedness.

G. EQUITY

Noncontrolling Interests - As a result of the Merger Transaction in 2017, we and our subsidiaries own 100% of ONEOK Partners. 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. ONEOK Partners' cash distributions paid prior to the Merger Transaction are reported as "Distributions to noncontrolling interests" in our accompanying Consolidated Statements of Changes in Equity.

In July 2018, we acquired the remaining 20% interest in WTLPG for $195 million with cash on hand. We are now the sole owner of the West Texas LPG pipeline system.

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, which represents a noncash financing activity, and is included in other expense in our Consolidated Statements of Income.

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. No shares were sold through our "at-the-market" equity program in 2019 or 2018.

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.

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 $1.5 billion, $1.3 billion and $829.4 million for 2019, 2018 and 2017, respectively. In addition to the increase in dividends paid per share outlined in the table below, dividends paid increased due to the increase in number of shares outstanding as a result of the closing of the Merger Transaction and our equity issuances. The following table sets forth the quarterly dividends per share paid on our common stock in the periods indicated:

	Years Ended December 31,		
	2019	**2018**	**2017**
First Quarter	**$ 0.860**	$ 0.770	$ 0.615
Second Quarter	**0.865**	0.795	0.615
Third Quarter	**0.890**	0.825	0.745
Fourth Quarter	**0.915**	0.855	0.745
Total	**$ 3.53**	$ 3.245	$ 2.72

Additionally, in February 2020, we paid a quarterly dividend of $0.935 per share ($3.74 per share on an annualized basis), which was paid to shareholders of record as of January 27, 2020.

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% per year. We paid dividends for the Series E Preferred Stock of $1.1 million in both 2019 and 2018 and $0.6 million in 2017. We paid quarterly dividends totaling $0.3 million for the Series E Preferred Stock in February 2020.

H. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive loss for the periods indicated:

	Risk-Management Assets/Liabilities (a)	Retirement and Other Postretirement Benefit Plan Obligations (a) (b)	Risk-Management Assets/Liabilities of Unconsolidated Affiliates (a)	Accumulated Other Comprehensive Loss (a)
	(*Thousands of dollars*)			
January 1, 2018	$ (81,915)	$ (105,411)	$ (1,204)	$ (188,530)
Beginning balance adjustments (c)	3,078	(805)	(2,273)	—
Other comprehensive income (loss) before reclassifications	(5,673)	(8,116)	2,396	(11,393)
Amounts reclassified to net income	36,870	12,887	28	49,785
Other comprehensive income (loss) attributable to ONEOK	31,197	4,771	2,424	38,392
Impact of adoption of ASU 2018-02 (d)	(17,020)	(20,340)	(741)	(38,101)
December 31, 2018	(64,660)	(121,785)	(1,794)	(188,239)
Other comprehensive loss before reclassifications	**(147,803)**	**(19,490)**	**(7,275)**	**(174,568)**
Amounts reclassified to net income	**(21,057)**	**9,794**	**70**	**(11,193)**
Other comprehensive income (loss)	**(168,860)**	**(9,696)**	**(7,205)**	**(185,761)**
December 31, 2019	**$ (233,520)**	**$ (131,481)**	**$ (8,999)**	**$ (374,000)**

(a) All amounts are presented net of tax.
(b) Includes amounts related to supplemental executive retirement plan.
(c) Reclassifications were made between categories to conform to current presentation.
(d) We elected to adopt this guidance in the first quarter 2018, which allows a reclassification from accumulated other comprehensive income/loss to retained earnings for the stranded tax effects resulting from the Tax Cuts and Jobs Act. After adopting and applying this guidance, our accumulated other comprehensive loss balance does not include stranded taxes resulting from the Tax Cuts and Jobs Act.

The following table sets forth information about the balance of accumulated other comprehensive loss at December 31, 2019, representing unrealized gains (losses) related to risk-management assets and liabilities:

	Risk-Management Assets/Liabilities (a)
	(*Thousands of dollars*)
Commodity derivative instruments expected to be realized within the next 24 months (b)	**$ 28,119**
Settled interest-rate swaps to be recognized over the life of the long-term, fixed-rate debt (c)	**(106,592)**
Interest-rate swaps with future settlement dates expected to be amortized over the life of long-term debt	**(155,047)**
Accumulated other comprehensive loss at December 31, 2019	**$ (233,520)**

(a) - All amounts are presented net of tax.
(b) - Based on December 31, 2019, commodity prices, we will realize $28.9 million in net gains, net of tax, over the next 12 months and $0.8 million in net loss, net of tax, thereafter.
(c) - Losses of $20.3 million, net of tax, will be reclassified into earnings during the next 12 months as the hedged items affect earnings.

The remaining amounts in accumulated other comprehensive loss relate primarily to our retirement and other postretirement benefit plan obligations, which are expected to be amortized over the average remaining service period of employees participating in these plans.

The following table sets forth the effect of reclassifications from accumulated other comprehensive loss to net income for the periods indicated:

Details about Accumulated Other Comprehensive Loss Components	Years Ended December 31, 2019	2018	2017	Affected Line Item in the Consolidated Statements of Income
	(*Thousands of dollars*)			
Risk-management assets/liabilities				
Commodity contracts	**$ 50,345**	$ (29,596)	$ (69,561)	Commodity sales revenues/ cost of sales and fuel
Interest-rate contracts	**(23,230)**	(18,287)	(21,025)	Interest expense
	27,115	(47,883)	(90,586)	Income before income taxes
	(6,058)	11,013	26,899	Income taxes
	21,057	(36,870)	(63,687)	Net income
Noncontrolling interests	**—**	—	(18,146)	Less: Net income attributable noncontrolling interests
	$ 21,057	$ (36,870)	$ (45,541)	Net income attributable to ONEOK
Retirement and other postretirement benefit plan obligations (a)				
Amortization of net loss	**$ (12,946)**	$ (18,398)	$ (15,265)	Other income (expense)
Amortization of unrecognized prior service credit	**227**	1,662	1,662	Other income (expense)
	(12,719)	(16,736)	(13,603)	Income before income taxes
	2,925	3,849	5,441	Income taxes
	$ (9,794)	$ (12,887)	$ (8,162)	Net income attributable to ONEOK
Risk-management assets/liabilities of unconsolidated affiliates				
Interest-rate contracts	**$ (91)**	$ (36)	$ (367)	Equity in net earnings from investments
	21	8	97	Income taxes
	(70)	(28)	(270)	Net income
Noncontrolling interests	**—**	—	(106)	Less: Net income attributable to noncontrolling interests
	$ (70)	$ (28)	$ (164)	Net income attributable to ONEOK
Total reclassifications for the period attributable to ONEOK	**$ 11,193**	$ (49,785)	$ (53,867)	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 K for additional detail of our net periodic benefit cost.

I. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS for the periods indicated:

	Year Ended December 31, 2019 Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS			
Net income available for common stock	**$ 1,277,477**	**413,560**	**$ 3.09**
Diluted EPS			
Effect of dilutive securities	**—**	**1,884**	
Net income available for common stock and common stock equivalents	**$ 1,277,477**	**415,444**	**$ 3.07**

	Year Ended December 31, 2018		
	Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS			
Net income attributable to ONEOK available for common stock	$ 1,150,603	411,485	$ 2.80
Diluted EPS			
Effect of dilutive securities	—	2,710	
Net income attributable to ONEOK available for common stock and common stock equivalents	$ 1,150,603	414,195	$ 2.78

	Year Ended December 31, 2017		
	Income	Shares	Per Share Amount
	(*Thousands, except per share amounts*)		
Basic EPS			
Net income attributable to ONEOK available for common stock	$ 387,074	297,477	$ 1.30
Diluted EPS			
Effect of dilutive securities	—	2,303	
Net income attributable to ONEOK available for common stock and common stock equivalents	$ 387,074	299,780	$ 1.29

J. SHARE-BASED PAYMENTS

The ONEOK, Inc. Equity Compensation Plan (ECP) and the ONEOK, Inc. Long-Term Incentive Plan (LTIP) historically provided 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. The ECP was terminated immediately following the issuance of new awards in February 2018. The awards issued prior to the termination remain subject to the terms of the ECP and the applicable award agreement. Similarly, the LTIP was terminated in May 2018, and the awards issued under the LTIP prior to the termination date remain subject to the terms of the LTIP and the applicable award agreement. In May 2018, our shareholders approved the ONEOK, Inc. Equity Incentive Plan (EIP), which has been used for all new equity awards since such date. We have reserved 8.5 million shares of common stock for issuance under the EIP and at December 31, 2019, we had 7.6 million shares available for issuance under the plan. This calculation of available shares reflects shares issued and estimated shares expected to be issued upon vesting of outstanding awards granted under the EIP, excluding estimated forfeitures expected to be returned to the plan.

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 that vest at the end 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% to 200%) 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. Performance unit awards are measured at fair value on the grant date based on a Monte Carlo model and adjusted for estimated forfeitures. Performance stock unit awards granted accrue dividend equivalents in the form of additional performance units prior to vesting. Compensation expense is recognized on a straight-line basis over the vesting period of the award.

Stock Compensation for Non-Employee Directors

The ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (the DSCP) and the LTIP historically provided for the granting of nonstatutory stock options, stock bonus awards, including performance unit awards and restricted stock awards. The DSCP was terminated in May 2018 and replaced by the EIP. Under the EIP, awards may be granted by the Executive Compensation Committee at any time, until grants have been made for all shares authorized under the EIP. The maximum number of shares of common stock and cash-based awards that can be issued to a participant under the EIP during any year is limited to $0.8 million in value as of the grant date. No performance unit awards or restricted stock awards have been made to nonemployee directors under the EIP, LTIP or DSCP. There are no options outstanding under the EIP, LTIP or DSCP.

General

For all awards outstanding, we used a 3% 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 was $46.5 million, $33.2 million and $27.7 million during 2019, 2018 and 2017, respectively, before related tax benefits of $31.7 million, $12.2 million and $11.1 million, respectively.

Restricted Stock Unit Activity

As of December 31, 2019, we had $15.4 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 1.8 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, 2018	**1,025,193**	**$ 34.68**
Granted	**262,399**	**$ 58.07**
Released to participants	**(541,871)**	**$ 19.73**
Forfeited	**(46,731)**	**$ 49.61**
Nonvested December 31, 2019	**698,990**	**$ 54.05**

	2019	2018	2017
Weighted-average grant date fair value (per share)	**$ 58.07**	$ 46.94	$ 45.11
Fair value of units granted (thousands of dollars)	**$ 15,238**	$ 13,907	$ 12,685
Grant date fair value of units vested (thousands of dollars)	**$ 10,691**	$ 9,552	$ 7,258

Performance Unit Activity

As of December 31, 2019, we had $23.5 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 1.8 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, 2018	**1,243,643**	**$ 44.08**
Granted	**338,427**	**$ 68.02**
Released to participants	**(636,628)**	**$ 23.59**
Forfeited	**(7,621)**	**$ 39.54**
Nonvested December 31, 2019	**937,821**	**$ 66.67**

	2019	2018	2017
Volatility (a)	**27.10%**	39.20%	40.59%
Dividend yield	**5.05%**	5.49%	4.68%
Risk-free interest rate	**2.47%**	2.44%	1.49%

(a) - Volatility was based on historical volatility over three years using daily stock price observations.

	2019	2018	2017
Weighted-average grant date fair value (per share)	**$ 68.02**	$ 59.57	$ 56.65
Fair value of units granted (thousands of dollars)	**$ 23,020**	$ 22,081	$ 17,621
Grant date fair value of units vested (thousands of dollars)	**$ 15,018**	$ 12,545	$ 8,704

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 employees are eligible to participate in the ESPP. Employees can choose to have up to 10% of their base pay withheld from each paycheck during the offering period to purchase our common stock, subject to terms and limitations of the plan. The purchase price of the stock is 85% of the lower of its grant date or exercise date market price. Approximately 62%, 60% and 58% of employees participated in the plan in 2019, 2018 and 2017, respectively. Under the plan, we sold 171,590 shares at $51.24 per share in 2019, 165,877 shares at $45.53 per share in 2018 and 151,803 shares at $44.20 per share in 2017.

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. Shares issued to employees under this program during 2019 and 2018 totaled 14,022 and 2,553, respectively. Compensation expense related to the Employee Stock Award Program was $1.0 million and $0.2 million for 2019 and 2018, respectively. No shares were issued to employees under this program during 2017. As of the date of this report, the next award will be issued when our common stock closes at or above $78.

Deferred Compensation Plan for Non-Employee Directors

The ONEOK, Inc. 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 EIP, 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.

K. EMPLOYEE BENEFIT PLANS

Retirement and Other Postretirement Benefit Plans

Retirement Plans - We have a defined benefit pension plan covering certain employees and former employees hired prior to January 1, 2005. Employees hired after December 31, 2004, and employees who accepted a one-time opportunity to opt out of our defined benefit pension plan historically were covered by our Profit Sharing Plan, which was merged into our 401(k) Plan as of December 31, 2018. 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 retirement 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.

Other 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 full-time service. The postretirement medical plan for pre-Medicare participants is contributory with retiree contributions adjusted periodically and contains other cost-sharing features such as deductibles and coinsurance. The postretirement medical plan for Medicare-eligible participants is an account-based plan under which participants may elect to purchase private insurance policies under a private exchange and/or seek reimbursement of other eligible medical expenses.

Obligations and Funded Status - The following table sets forth our retirement and other postretirement benefit plans benefit obligations and fair value of plan assets for the periods indicated:

	Retirement Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2019	2018	2019	2018
Change in benefit obligation		*(Thousands of dollars)*		
Benefit obligation, beginning of period	**$ 466,994**	$ 481,615	**$ 46,840**	$ 57,938
Service cost	**7,825**	7,339	**468**	845
Interest cost	**20,528**	17,659	**2,038**	2,108
Plan participants' contributions	**—**	—	**1,142**	1,050
Actuarial loss (gain)	**55,954**	(24,345)	**5,101**	(10,233)
Benefits paid	**(16,452)**	(15,274)	**(3,280)**	(4,868)
Benefit obligation, end of period	**534,849**	466,994	**52,309**	46,840
Change in plan assets				
Fair value of plan assets, beginning of period	**290,684**	306,008	**30,800**	34,133
Actual return on plan assets	**58,060**	(12,350)	**8,087**	(998)
Employer contributions	**14,500**	12,300	**2,000**	1,100
Plan participants' contributions	**—**	—	**1,142**	1,050
Benefits paid	**(16,452)**	(15,274)	**(2,969)**	(4,485)
Fair value of plan assets, end of period	**346,792**	290,684	**39,060**	30,800
Balance at December 31	**$ (188,057)**	$ (176,310)	**$ (13,249)**	$ (16,040)
Current liabilities	**$ (4,616)**	$ (4,514)	**$ —**	$ —
Noncurrent liabilities	**(183,441)**	(171,796)	**(13,249)**	(16,040)
Balance at December 31	**$ (188,057)**	$ (176,310)	**$ (13,249)**	$ (16,040)

The table above includes the supplemental executive retirement plan obligation. ONEOK has investments included in other assets on the Consolidated Balance Sheets, which totaled $98.9 million and $87.7 million at December 31, 2019 and 2018, respectively, for the purpose of funding the obligation. These assets are not assets of the supplemental executive retirement plan and are excluded from the table above.

The accumulated benefit obligation for our retirement plans was $498.8 million and $434.4 million at December 31, 2019 and 2018, respectively.

The actuarial gains and losses impacting our benefit obligations for our retirement and other postretirement benefit plans are due primarily to changes in the discount rate assumptions discussed in the "Actuarial Assumptions" section below.

Components of Net Periodic Benefit Cost - The following table sets forth the components of net periodic benefit cost for our retirement and other postretirement benefit plans for the periods indicated:

	Retirement Benefits			Other Postretirement Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2019	2018	2017	2019	2018	2017
			(Thousands of dollars)			
Components of net periodic benefit cost						
Service cost	**$ 7,825**	$ 7,339	$ 6,896	**$ 468**	$ 845	$ 662
Interest cost	**20,528**	17,659	18,645	**2,038**	2,108	2,261
Expected return on plan assets	**(23,600)**	(23,917)	(21,376)	**(2,285)**	(2,690)	(2,257)
Amortization of prior service credit	**—**	—	—	**(227)**	(1,662)	(1,662)
Amortization of net loss	**12,649**	17,060	13,586	**297**	1,338	1,679
Net periodic benefit cost	**$ 17,402**	$ 18,141	$ 17,751	**$ 291**	$ (61)	$ 683

Other Comprehensive Income (Loss) - The following table sets forth the amounts recognized in other comprehensive income (loss) related to our retirement and other postretirement benefits for the periods indicated:

	Retirement Benefits			Other Postretirement Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2019	2018	2017	**2019**	2018	2017
	(Thousands of dollars)					
Net gain (loss)	**$ (25,389)**	$ (16,351)	$ (16,572)	**$ 700**	$ 6,545	$ (328)
Prior service cost	**(601)**	—	—	**—**	—	—
Amortization of prior service credit	**—**	—	—	**(227)**	(1,662)	(1,662)
Amortization of net loss	**12,649**	17,060	13,586	**297**	1,338	1,679
Deferred income taxes (a)	**3,068**	(18,928)	(960)	**(177)**	(2,831)	82
Total recognized in other comprehensive income (loss)	**$ (10,273)**	$ (18,219)	$ (3,946)	**$ 593**	$ 3,390	$ (229)

(a) - Year ended December 31, 2018, includes the impact of adopting ASU 2018-02, "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income."

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:

	Retirement Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2019	2018	**2019**	2018
	(Thousands of dollars)			
Prior service credit (cost)	**$ (601)**	$ —	**$ —**	$ 227
Accumulated loss	**(172,952)**	(160,212)	**(4,110)**	(5,108)
Accumulated other comprehensive loss	**(173,553)**	(160,212)	**(4,110)**	(4,881)
Deferred income taxes	**46,354**	43,286	**1,389**	1,567
Accumulated other comprehensive loss, net of tax	**$ (127,199)**	$ (116,926)	**$ (2,721)**	$ (3,314)

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for retirement and other postretirement benefits for the periods indicated:

	Retirement Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2019	2018	**2019**	2018
Discount rate	**3.50%**	4.50%	**3.50%**	4.50%
Compensation increase rate	**3.70%**	3.65%	**NA**	NA

The following table sets forth the weighted-average assumptions used to determine net periodic benefit costs for the periods indicated:

	Years Ended December 31,		
	2019	2018	2017
Discount rate - retirement plans	**4.50%**	3.75%	4.50%
Discount rate - other postretirement plans	**4.50%**	3.75%	4.25%
Expected long-term return on plan assets	**7.50%**	8.00%	7.75%
Compensation increase rate	**3.65%**	3.00%	3.10%

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 utilizing portfolios of high quality bonds matched to the estimated benefit cash flows of our retirement and other postretirement benefit plans. Bonds selected to be included in the portfolios are only those rated by S&P or Moody's as an AA or Aa2 rating 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:

	2019	2018
Health care cost-trend rate assumed for next year	**7.00%**	6.50%
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	**2024**	2022

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 for our defined benefit pension plan 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, real estate and hedge funds. The target allocation for the assets of our retirement plan as of December 31, 2019, is as follows:

Domestic and international equities	42%
Long duration fixed income	30%
Return-seeking credit	11%
Hedge funds	10%
Real estate funds	7%
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.

The following tables set forth the plan assets by fair value category as of the measurement date for our defined benefit pension and other postretirement benefit plans:

	Pension Benefits December 31, 2019					
Asset Category	**Level 1**	**Level 2**	**Level 3**	**Subtotal**	**Measured at NAV (d)**	**Total**
			(*Thousands of dollars*)			
Investments:						
Equity securities (a)	**$ 47**	**$ —**	**$ —**	**$ 47**	**$ 149,985**	**$ 150,032**
Real estate funds	—	—	—	—	**23,885**	**23,885**
Government obligations	—	—	—	—	**50,708**	**50,708**
Corporate obligations (b)	—	—	—	—	**85,898**	**85,898**
Common/collective trusts	—	**3,263**	—	**3,263**	—	**3,263**
Cash	**63**	—	—	**63**	—	**63**
Other investments (c)	—	—	—	—	**32,943**	**32,943**
Fair value of plan assets	**$ 110**	**$ 3,263**	**$ —**	**$ 3,373**	**$ 343,419**	**$ 346,792**

(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, 2018 Level 1	Level 2	Level 3	Subtotal	Measured at NAV (d)	Total
			(*Thousands of dollars*)			
Investments:						
Equity securities (a)	$ 58	$ —	$ —	$ 58	$ 116,790	$ 116,848
Real estate funds	—	—	—	—	20,569	20,569
Government obligations	—	—	—	—	48,913	48,913
Corporate obligations (b)	—	—	—	—	69,377	69,377
Common/collective trusts	—	3,961	—	3,961	—	3,961
Cash	95	—	—	95	—	95
Other investments (c)	—	—	—	—	30,921	30,921
Fair value of plan assets	$ 153	$ 3,961	$ —	$ 4,114	$ 286,570	$ 290,684

(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	Other Postretirement Benefits December 31, 2019 Level 1	Level 2	Level 3	Total
		(*Thousands of dollars*)		
Investments:				
Equity securities (a)	**$ 2,043**	**$ —**	**$ —**	**$ 2,043**
Money market funds	**—**	**2,428**	**—**	**2,428**
Insurance and group annuity contracts	**—**	**34,589**	**—**	**34,589**
Fair value of plan assets	**$ 2,043**	**$ 37,017**	**$ —**	**$ 39,060**

(a) - This category represents securities of the respective market sector from diverse industries.

Asset Category	Other Postretirement Benefits December 31, 2018 Level 1	Level 2	Level 3	Total
		(*Thousands of dollars*)		
Investments:				
Equity securities (a)	$ 1,792	$ —	$ —	$ 1,792
Money market funds	1	413	—	414
Insurance and group annuity contracts	—	28,594	—	28,594
Fair value of plan assets	$ 1,793	$ 29,007	$ —	$ 30,800

(a) - This category represents securities of the respective market sector from diverse industries.

Contributions - During 2019, we made $14.5 million in contributions to our defined benefit pension plan and $2.0 million in contributions to our other postretirement benefit plans. We contributed $12.1 million to our defined benefit pension plan in January 2020 and expect to make $2.0 million in contributions to our other postretirement plans in the remainder of 2020.

Pension and Other Postretirement Benefit Payments - Benefit payments for our defined benefit pension and other postretirement benefit plans for the period ending December 31, 2019, were \$16.5 million and \$3.3 million, respectively. The following table sets forth the defined benefit pension and other postretirement benefits payments expected to be paid in 2020 through 2029:

	Pension Benefits	Other Postretirement Benefits
Benefits to be paid in:	(*Thousands of dollars*)	
2020	$ 18,277	$ 3,422
2021	$ 19,252	$ 3,399
2022	$ 20,202	$ 3,519
2023	$ 21,170	$ 3,454
2024	$ 22,228	$ 3,446
2025 through 2029	$ 123,959	$ 16,385

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2019, 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 historically maintained a profit-sharing plan for all employees hired after December 31, 2004, which was merged into our 401(k) Plan as of December 31, 2018, and ceased to exist as a separate plan. We match 100% of employee 401(k) contributions up to 6% of each participant's eligible compensation, subject to certain limits, and generally make a quarterly profit sharing contribution equal to 1% of each profit-sharing participant's eligible compensation during the quarter and an annual discretionary profit-sharing contribution. Our contributions made to the plan, including profit-sharing contributions, were \$30.4 million, \$28 million and \$21.1 million in 2019, 2018 and 2017, respectively.

Nonqualified Deferred Compensation Plan - The 2019 Nonqualified Deferred Compensation Plan and its predecessor nonqualified deferred compensation plans (collectively, the NQDC Plan) provide select employees, as approved by our Chief Executive Officer, with the option to defer portions of their compensation and provide 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 NQDC 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 2019, 2018 and 2017.

L. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2019	**2018**	**2017**
	(*Thousands of dollars*)		
Current tax expense (benefit)			
Federal	**$ (1,278)**	$ 260	$ 295
State	**963**	1,633	1,670
Total current tax expense (benefit)	**(315)**	1,893	1,965
Deferred tax expense			
Federal	**327,806**	319,551	376,728
State	**44,923**	41,459	68,589
Total deferred tax expense	**372,729**	361,010	445,317
Total provision for income taxes	**$ 372,414**	$ 362,903	$ 447,282

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31,		
	2019	**2018**	**2017**
	(*Thousands of dollars*)		
Income before income taxes	**$ 1,650,991**	$ 1,517,935	$ 1,040,801
Less: Net income attributable to noncontrolling interests	**—**	3,329	205,678
Net income attributable to ONEOK before income taxes	**1,650,991**	1,514,606	835,123
Federal statutory income tax rate	**21.0%**	21.0%	35.0%
Provision for federal income taxes	**346,708**	318,067	292,293
State income taxes, net of federal benefit	**34,545**	38,668	16,197
Deferred tax rate change, inclusive of valuation allowance	**11,340**	5,552	141,283
Excess tax benefits from share-based compensation	**(20,983)**	(4,644)	—
Other, net	**804**	5,260	(2,491)
Income tax provision	**$ 372,414**	$ 362,903	$ 447,282

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, 2019	**December 31, 2018**
Deferred tax assets	(*Thousands of dollars*)	
Employee benefits and other accrued liabilities	**$ 99,510**	$ 91,587
Federal net operating loss	**858,030**	420,318
State net operating loss and benefits	**171,779**	108,004
Derivative instruments	**83,710**	22,108
Other	**12,769**	13,378
Total deferred tax assets	**1,225,798**	655,395
Valuation allowance for state net operating loss and tax credits		
Carryforward expected to expire prior to utilization	**(94,794)**	(73,820)
Net deferred tax assets	**1,131,004**	581,575
Deferred tax liabilities		
Excess of tax over book depreciation	**84,631**	73,113
Investment in partnerships (a)	**1,582,436**	728,193
Total deferred tax liabilities	**1,667,067**	801,306
Net deferred tax assets (liabilities)	**$ (536,063)**	$ (219,731)

(a) Due primarily to excess of tax over book depreciation.

In December 2017, the Tax Cuts and Jobs Act was signed into law. The Tax Cuts and Jobs Act made extensive changes to the U.S. tax laws and included provisions that, beginning in 2018, reduced the U.S. corporate tax rate to 21% from 35%, increased expensing for capital investment, limited the interest deduction, and limited the use of net operating losses to offset future taxable income. We revalued our deferred tax assets and liabilities as required at enactment. At that time, our net deferred tax assets represented expected corporate tax benefits in the future. The reduction in the federal corporate tax rate reduced 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.

Tax benefits related to certain state net operating loss, tax credit carryforwards and charitable contribution carryforwards will begin expiring in 2020. Due to the Tax Cuts and Jobs Act and the impact of increased expensing for capital investment, we believe that it is more likely than not that the tax benefits of certain carryforwards will not be utilized prior to their expirations; therefore, we recorded a valuation allowance of $11.3 million, $5.6 million and $54.1 million through net income related to these tax benefits in 2019, 2018 and 2017, respectively.

M. 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, 2019	December 31, 2018
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 307,209**	$ 381,623
Overland Pass Pipeline	50%	**417,473**	429,295
Roadrunner	50%	**80,816**	93,857
Other	Various	**56,346**	64,375
Investments in unconsolidated affiliates (a)		**$ 861,844**	$ 969,150

(a) - Equity-method goodwill (Note A) was $38.8 million at December 31, 2019 and 2018.

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, 2019	2018	2017
		(Thousands of dollars)	
Northern Border Pipeline	**$ 68,871**	$ 67,854	$ 68,153
Overland Pass Pipeline	**63,698**	65,887	60,067
Roadrunner	**26,839**	22,993	19,150
Other	**(4,867)**	1,649	11,908
Equity in net earnings from investments	**$ 154,541**	$ 158,383	$ 159,278
Impairment of equity investments	**$ —**	$ —	$ (4,270)

Impairment Charges - In 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.

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2019	December 31, 2018
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 149,564**	$ 158,723
Property, plant and equipment, net	**$ 2,314,631**	$ 2,413,662
Other noncurrent assets	**$ 13,252**	$ 16,273
Current liabilities	**$ 88,142**	$ 83,057
Long-term debt	**$ 581,327**	$ 480,731
Other noncurrent liabilities	**$ 76,685**	$ 47,826
Accumulated other comprehensive income (loss)	**$ (28,373)**	$ 2,053
Owners' equity	**$ 1,759,666**	$ 1,974,991

	Years Ended December 31,					
		2019		**2018**		**2017**
	(*Thousands of dollars*)					
Income Statement						
Revenues	**$**	**634,135**	$	637,762	$	639,102
Operating expenses	**$**	**291,210**	$	276,373	$	277,121
Net income	**$**	**315,274**	$	337,694	$	347,692
Distributions paid to us (a)	**$**	**257,644**	$	197,285	$	196,114

(a) As determined by the Northern Border Pipeline Management Committee, we received an additional distribution of $50.0 million from Northern Border Pipeline during the year ended December 31, 2019.

We incurred expenses in transactions with unconsolidated affiliates of $164.7 million, $153.9 million and $156.1 million for 2019, 2018 and 2017, respectively, primarily related to Overland Pass Pipeline and Northern Border Pipeline. Accounts payable to our equity-method investees at December 31, 2019 and 2018, were $13.5 million and $14.7 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% 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 2019 and 2018, we made no contributions to Northern Border Pipeline. In 2017, we made equity contributions of $83 million to Northern Border Pipeline.

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 reduced tariff rates 12.5% by January 2020, compared with previous tariff rates and requires new rates to be established by January 2024. We do not expect the impact of lower tariff rates on Northern Border Pipeline's earnings and cash distributions to be material to us.

Overland Pass Pipeline - The Overland Pass Pipeline agreement provides that distributions to Overland Pass Pipeline'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 requires the unanimous approval of the Overland Pass Pipeline Company Management Committee. Cash distributions are equal to 100% of available cash as defined in the limited liability company agreement.

Roadrunner - The Roadrunner 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 agreement. Cash distributions are equal to 100% of available cash, as defined in the limited liability company agreement. In 2019, 2018 and 2017, our contributions to Roadrunner were not material.

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, 2019, 2018 and 2017, were not material.

N. COMMITMENTS AND CONTINGENCIES

Commitments - 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*)
2020	$ 61.6
2021	48.1
2022	40.1
2023	36.4
2024	34.3
Thereafter	177.9
Total	$ 398.4

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 laws and regulations 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 affect adversely 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., 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 September 2019, we settled *Sinclair Oil Corporation v. ONEOK Energy Services Company, L.P.* (filed in the United States District Court for the District of Wyoming) for an immaterial amount with cash on hand. This was the last remaining case arising from the Gas Index Pricing Litigation.

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 affect adversely our consolidated results of operations, financial position or cash flows.

O. LEASES

Adoption of ASC Topic 842: Leases - We adopted Topic 842 using the modified retrospective method and the optional transition method to record the adoption impact through a cumulative-effect adjustment to retained earnings as of January 1, 2019. Results for reporting periods beginning after January 1, 2019, are presented under Topic 842, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods.

Practical Expedients and Policies Elected - We applied the short-term policy election, which allows us to exclude from recognition leases with an initial term of 12 months or less. We elected the hindsight expedient, which allows us to use hindsight in assessing lease term; the package of practical expedients permitted under the guidance, which among other things, allows us to carry forward the historical lease classification; and the land easement expedient, which allows us to apply the guidance prospectively at adoption for land easements on existing agreements.

Adoption - Adoption of Topic 842 resulted in new operating lease assets and lease liabilities on our Consolidated Balance Sheet of $17.5 million and $17.4 million, respectively, as of January 1, 2019. The difference between the lease assets and lease liabilities was recorded as an adjustment to the beginning balance of retained earnings, which represents the cumulative impact of adopting the standard. Our accounting for finance leases did not change. Adoption of Topic 842 did not materially impact our Consolidated Financial Statements.

Leases - We lease certain buildings, warehouses, office space, pipeline capacity, land and equipment, including pipeline equipment, rail cars, and information technology equipment. Our lease payments are generally straight-line and the exercise of lease renewal options, which vary in term, is at our sole discretion. We include renewal periods in a lease term if we are reasonably certain to exercise available renewal options. Our lease agreements do not include any residual value guarantees or material restrictive covenants.

Through ONEOK Leasing Company, L.L.C. and ONEOK Parking Company, L.L.C., we own an office building and a parking garage and lease excess space in these facilities to affiliates and others. Our consolidated lease income is not material.

The following table sets forth supplemental information about our cash flows:

	Year Ended December 31, 2019	
	(*Thousands of dollars*)	
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows for operating leases	$	**6,213**
Financing cash flows for finance lease	$	**1,764**
Right-of-use assets obtained in exchange for operating lease liabilities (noncash)	$	**4,097**

The following table sets forth information about our lease assets and liabilities included in our Consolidated Balance Sheet for the period indicated:

Leases	**Location in our Consolidated Balance Sheet**	**December 31, 2019**	
		(*Thousands of dollars*)	
Assets			
Operating leases	Other assets	$	**15,147**
Finance lease	Property, plant and equipment		**28,286**
Finance lease	Accumulated depreciation		**(1,320)**
Total leased assets		$	**42,113**
Liabilities			
Current			
Operating leases	Other current liabilities	$	**1,883**
Finance lease	Finance lease liability		**1,949**
Noncurrent			
Operating leases	Other deferred credits		**13,509**
Finance lease	Finance lease liability		**24,296**
Total lease liabilities		$	**41,637**

The following table sets forth information about our leases for the period indicated:

	Location in our Consolidated Statement of Income	Year Ended December 31, 2019 Lease Cost	At December 31, 2019 Weighted-Average Remaining Lease Term	At December 31, 2019 Weighted-Average Discount Rate (a)
		(*Thousands of dollars*)	(*Years*)	
Operating leases	Operations and maintenance	**$ 6,803**	**10.4**	**4.58%**
Finance lease			**8.8**	**10.00%**
Amortization of lease assets	Depreciation and amortization	**1,131**		
Interest on lease liabilities	Interest expense	**2,721**		
Total lease cost		**$ 10,655**		

(a) - Our weighted-average discount rates represent the rate implicit in the lease or our incremental borrowing rate for a term equal to the remaining term of the lease.

The following table sets forth the maturity of our lease liabilities as of December 31, 2019:

	Finance Lease	Operating Leases
	(*Millions of dollars*)	
2020	$ 4.5	$ 2.5
2021	4.5	2.1
2022	4.5	2.0
2023	4.5	1.9
2024	4.5	1.9
2025 and beyond	17.1	9.2
Total lease payments	39.6	19.6
Less: Interest	13.4	4.2
Present value of lease liabilities	$ 26.2	$ 15.4

Our future lease payments presented under the previous accounting standard as of December 31, 2018, are not materially different than those presented above.

As of December 31, 2019, we have entered into an additional operating lease that had not yet commenced with an estimated present value of $75.6 million and a lease term of 10 years, which is excluded from our maturities table above and our lease right-of-use assets and liabilities.

P. REVENUES

Accounting Policies - See Note A for revenue recognition accounting policies.

Contract Assets and Contract Liabilities - The following tables set forth the changes in our contract asset and contract liability balances for the periods indicated:

Contract Assets		*(Millions of dollars)*
Balance at January 1, 2018 (a)	$	6.4
Amounts invoiced in excess of revenue recognized		(0.9)
Net additions		0.7
Balance at December 31, 2018 (b)		6.2
Amounts invoiced in excess of revenue recognized		**(1.7)**
Net additions		**0.5**
Balance at December 31, 2019 (c)	**$**	**5.0**

(a) - Balance includes $0.9 million of current assets.
(b) - Contract assets of $1.7 million and $4.5 million are included in other current assets and other assets, respectively, in our Consolidated Balance Sheet.
(c) - Contract assets of $1.3 million and $3.7 million are included in other current assets and other assets, respectively, in our Consolidated Balance Sheet.

Contract Liabilities		*(Millions of dollars)*
Balance at January 1, 2018 (a)	$	33.3
Revenue recognized included in beginning balance		(19.5)
Net additions		17.9
Balance at December 31, 2018 (b)		31.7
Revenue recognized included in beginning balance		**(15.6)**
Net additions		**41.0**
Balance at December 31, 2019 (c)	**$**	**57.1**

(a) - Balance includes $19.5 million of current liabilities.
(b) - Contract liabilities of $15.6 million and $16.1 million are included in other current liabilities and other deferred credits, respectively, in our Consolidated Balance Sheet.
(c) - Contract liabilities of $22.2 million and $34.9 million are included in other current liabilities and other deferred credits, respectively, in our Consolidated Balance Sheet.

In 2019, net additions for contract liabilities relate primarily to deferred revenue on contributions in aid of construction received from customers and NGL storage contracts.

Receivables from Customers and Revenue Disaggregation - Substantially all of the balances in accounts receivable on our Consolidated Balance Sheets at December 31, 2019, and December 31, 2018, relate to customer receivables. Revenues sources are disaggregated in Note Q.

Practical Expedients - We do not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) variable consideration on contracts for which we recognize revenue at the amount to which we have the right to invoice for services performed.

Transaction Price Allocated to Unsatisfied Performance Obligations - The following table presents aggregate value allocated to unsatisfied performance obligations as of December 31, 2019, and the amounts we expect to recognize in revenue in future periods, related primarily to firm transportation and storage contracts with remaining contract terms ranging from one month to 24 years:

Expected Period of Recognition in Revenue		*(Millions of dollars)*
2020	$	343.5
2021		290.4
2022		214.8
2023		166.4
2024 and beyond		807.2
Total estimated transaction price allocated to unsatisfied performance obligations	$	1,822.3

The table above excludes variable consideration allocated entirely to wholly unsatisfied performance obligations, wholly unsatisfied promises to transfer distinct goods or services that are part of a single performance obligation and consideration we determine to be fully constrained. Information on the nature of the variable consideration excluded and the nature of the performance obligations to which the variable consideration relates can be found in the description of the major contract types discussed in Note A. The amounts we determined to be fully constrained relate to future sales obligations under long-term sales contracts where the transaction price is not known and minimum volume agreements, which we consider to be fully constrained until invoiced.

Q. 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 corporate 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.

For each of the years ended December 31, 2019, 2018 and 2017, we had no single customer from which we received 10% 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, 2019	**Natural Gas Gathering and Processing**	**Natural Gas Liquids (a)**	**Natural Gas Pipelines (b)**	**Total Segments**
		(Thousands of dollars)		
NGL and condensate sales	$ 1,224,378	$ 7,910,833	$ —	$ 9,135,211
Residue natural gas sales	966,149	—	1,244	967,393
Gathering, processing and exchange services revenue	164,299	414,238	—	578,537
Transportation and storage revenue	—	197,483	466,266	663,749
Other	13,813	9,962	4,477	28,252
Total revenues (c)	2,368,639	8,532,516	471,987	11,373,142
Cost of sales and fuel (exclusive of depreciation and operating costs)	(1,302,310)	(6,690,918)	(4,628)	(7,997,856)
Operating costs	(368,352)	(456,892)	(157,230)	(982,474)
Equity in net earnings from investments	(6,292)	65,123	95,710	154,541
Noncash compensation expense and other	10,965	15,936	2,977	29,878
Segment adjusted EBITDA	$ 702,650	$ 1,465,765	$ 408,816	$ 2,577,231
Depreciation and amortization	$ (219,519)	$ (196,132)	$ (57,250)	$ (472,901)
Investments in unconsolidated affiliates	$ 34,426	$ 439,393	$ 388,025	$ 861,844
Total assets	$ 6,795,744	$ 12,551,476	$ 2,094,072	$ 21,441,292
Capital expenditures	$ 926,489	$ 2,796,604	$ 99,221	$ 3,822,314

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $1.4 billion, of which $1.2 billion related to sales within the segment, and cost of sales and fuel of $496.8 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $285.3 million and cost of sales and fuel of $20.0 million.
(c) - Intersegment revenues for the Natural Gas Gathering and Processing segment totaled $1.2 billion. Intersegment revenues for the Natural Gas Liquids and Natural Gas Pipelines segments were not material.

Year Ended December 31, 2019	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
NGL and condensate sales	**$ 9,135,211**	**$ (1,190,424)**	**$ 7,944,787**
Residue natural gas sales	**967,393**	**(1,418)**	**965,975**
Gathering, processing and exchange services revenue	**578,537**	**—**	**578,537**
Transportation and storage revenue	**663,749**	**(15,646)**	**648,103**
Other	**28,252**	**(1,287)**	**26,965**
Total revenues (a)	**$ 11,373,142**	**$ (1,208,775)**	**$ 10,164,367**
Cost of sales and fuel (exclusive of depreciation and operating costs)	**$ (7,997,856)**	**$ 1,209,816**	**$ (6,788,040)**
Operating costs	**$ (982,474)**	**$ (390)**	**$ (982,864)**
Depreciation and amortization	**$ (472,901)**	**$ (3,634)**	**$ (476,535)**
Equity in net earnings from investments	**$ 154,541**	**$ —**	**$ 154,541**
Investments in unconsolidated affiliates	**$ 861,844**	**$ —**	**$ 861,844**
Total assets	**$ 21,441,292**	**$ 370,829**	**$ 21,812,121**
Capital expenditures	**$ 3,822,314**	**$ 26,035**	**$ 3,848,349**

(a) - Noncustomer revenue for the year ended December 31, 2019, totaled $139.6 million related primarily to gains from derivatives on commodity contracts.

Year Ended December 31, 2018	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total Segments
		(Thousands of dollars)		
NGL and condensate sales	$ 1,775,991	$ 10,319,847	$ —	$ 12,095,838
Residue natural gas sales	1,084,162	—	9,772	1,093,934
Gathering, processing and exchange services revenue	163,194	404,897	—	568,091
Transportation and storage revenue	—	199,018	414,969	613,987
Other	11,230	10,816	6,994	29,040
Total revenues (c)	3,034,577	10,934,578	431,735	14,400,890
Cost of sales and fuel (exclusive of depreciation and operating costs)	(2,041,448)	(9,176,813)	(15,984)	(11,234,245)
Operating costs	(368,939)	(394,115)	(144,259)	(907,313)
Equity in net earnings from investments	410	67,126	90,847	158,383
Noncash compensation expense and other	7,007	9,829	3,912	20,748
Segment adjusted EBITDA	$ 631,607	$ 1,440,605	$ 366,251	$ 2,438,463
Depreciation and amortization	$ (196,090)	$ (174,007)	$ (55,118)	$ (425,215)
Investments in unconsolidated affiliates	$ 42,630	$ 451,040	$ 475,480	$ 969,150
Total assets	$ 6,078,473	$ 9,663,640	$ 2,131,669	$ 17,873,782
Capital expenditures	$ 694,611	$ 1,306,341	$ 119,185	$ 2,120,137

(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 $1.1 billion related to sales within the segment, and cost of sales and fuel of $506.0 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $266.6 million and cost of sales and fuel of $26.0 million.
(c) - Intersegment revenues for the Natural Gas Gathering and Processing segment totaled $1.8 billion. Intersegment revenues for the Natural Gas Liquids and Natural Gas Pipelines segments were not material.

Year Ended December 31, 2018	Total Segments	Other and Eliminations	Total
	(*Thousands of dollars*)		
Reconciliations of total segments to consolidated			
NGL and condensate sales	$ 12,095,838	$ (1,794,342)	$ 10,301,496
Residue natural gas sales	1,093,934	(2,832)	1,091,102
Gathering, processing and exchange services revenue	568,091	(21)	568,070
Transportation and storage revenue	613,987	(10,550)	603,437
Other	29,040	51	29,091
Total revenues (a)	$ 14,400,890	$ (1,807,694)	$ 12,593,196
Cost of sales and fuel (exclusive of depreciation and operating costs)	$ (11,234,245)	$ 1,811,537	$ (9,422,708)
Operating costs	$ (907,313)	$ 245	$ (907,068)
Depreciation and amortization	$ (425,215)	$ (3,342)	$ (428,557)
Equity in net earnings from investments	$ 158,383	$ —	$ 158,383
Investments in unconsolidated affiliates	$ 969,150	$ —	$ 969,150
Total assets	$ 17,873,782	$ 357,889	$ 18,231,671
Capital expenditures	$ 2,120,137	$ 21,338	$ 2,141,475

(a) - Noncustomer revenue for the year ended December 31, 2018, totaled $(16.2) million related primarily to losses from derivatives on commodity contracts.

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 operating costs)	(2,216,355)	(9,176,494)	(43,424)	(11,436,273)
Operating costs	(307,376)	(358,278)	(125,308)	(790,962)
Equity in net earnings from investments	12,098	59,876	87,304	159,278
Other	3,531	3,631	1,314	8,476
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)
Investments in unconsolidated affiliates	$ 55,841	$ 457,467	$ 489,848	$ 1,003,156
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	$ (790,962)	$ (31,748)	$ (822,710)
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
Investments in unconsolidated affiliates	$ 1,003,156	$ —	$ 1,003,156
Total assets	$ 16,332,883	$ 513,054	$ 16,845,937
Capital expenditures	$ 494,036	$ 18,357	$ 512,393

	Years Ended December 31,		
	2019	**2018**	**2017**
Reconciliation of net income to total segment adjusted EBITDA	(*Thousands of dollars*)		
Net income	**$ 1,278,577**	$ 1,155,032	$ 593,519
Add:			
Interest expense, net of capitalized interest	**491,773**	469,620	485,658
Depreciation and amortization	**476,535**	428,557	406,335
Income taxes	**372,414**	362,903	447,282
Impairment charges	**—**	—	20,240
Noncash compensation expense	**26,699**	37,954	13,421
Other corporate costs and noncash items (a)	**(68,767)**	(15,603)	46,774
Total segment adjusted EBITDA	**$ 2,577,231**	$ 2,438,463	$ 2,013,229

(a) - The year ended December 31, 2019, includes higher equity AFUDC related to our capital-growth projects compared with 2018 and 2017. 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.

R. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2019	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(*Thousands of dollars, except per share amounts*)			
Total revenues	**$ 2,779,958**	**$ 2,457,575**	**$ 2,263,228**	**$ 2,663,606**
Operating income	**$ 468,742**	**$ 476,146**	**$ 482,151**	**$ 487,314**
Net income	**$ 337,208**	**$ 311,963**	**$ 309,155**	**$ 320,251**
Net income available to common shareholders	**$ 336,933**	**$ 311,688**	**$ 308,880**	**$ 319,976**
Earnings per share total				
Basic	**$ 0.82**	**$ 0.75**	**$ 0.75**	**$ 0.77**
Diluted	**$ 0.81**	**$ 0.75**	**$ 0.74**	**$ 0.77**

Year Ended December 31, 2018		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
				(Thousands of dollars except per share amounts)				
Total revenues	$	3,102,077	$	2,960,529	$	3,393,890	$	3,136,700
Operating income	$	419,699	$	448,366	$	495,534	$	471,865
Net income	$	266,049	$	282,179	$	313,916	$	292,888
Net income available to common shareholders	$	264,233	$	280,773	$	312,984	$	292,613
Earnings per share total								
Basic	$	0.65	$	0.68	$	0.76	$	0.71
Diluted	$	0.64	$	0.68	$	0.75	$	0.70

S. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

ONEOK and ONEOK Partners are issuers of certain public debt securities. We, ONEOK Partners and the Intermediate Partnership have cross guarantees in place for the indebtedness of ONEOK and ONEOK Partners. The Intermediate Partnership holds all of ONEOK Partners' interests and equity in its subsidiaries, as well as a 50% 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, 2019					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
	(*Millions of dollars*)					
Revenues						
Commodity sales	$ —	$ —	$ —	$ 8,916.1	$ —	$ 8,916.1
Services	—	—	—	1,250.4	(2.1)	1,248.3
Total revenues	—	—	—	10,166.5	(2.1)	10,164.4
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	6,788.0	—	6,788.0
Operating expenses	—	—	—	1,461.5	(2.1)	1,459.4
(Gain) loss on sale of assets	—	—	2.7	(0.1)	—	2.6
Operating income	—	—	(2.7)	1,917.1	—	1,914.4
Equity in net earnings from investments	1,898.7	1,906.2	1,908.9	116.3	(5,675.6)	154.5
Other income (expense), net	34.4	305.7	308.3	42.1	(616.6)	73.9
Interest expense, net	(287.4)	(308.3)	(308.3)	(204.4)	616.6	(491.8)
Income before income taxes	1,645.7	1,903.6	1,906.2	1,871.1	(5,675.6)	1,651.0
Income taxes	(367.1)	—	—	(5.3)	—	(372.4)
Net income	1,278.6	1,903.6	1,906.2	1,865.8	(5,675.6)	1,278.6
Less: Preferred stock dividends	1.1	—	—	—	—	1.1
Net income available to common shareholders	$ 1,277.5	$ 1,903.6	$ 1,906.2	$ 1,865.8	$ (5,675.6)	$ 1,277.5
Net income	$ 1,278.6	$ 1,903.6	$ 1,906.2	$ 1,865.8	$ (5,675.6)	$ 1,278.6
Other comprehensive income (loss), net of tax	(183.8)	(2.6)	(20.9)	(20.5)	42.0	(185.8)
Comprehensive income	$ 1,094.8	$ 1,901.0	$ 1,885.3	$ 1,845.3	$ (5,633.6)	$ 1,092.8

	Year Ended December 31, 2018					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
	(*Millions of dollars*)					
Revenues						
Commodity sales	$ —	$ —	$ —	$ 11,395.6	$ —	$ 11,395.6
Services	—	—	—	1,199.7	(2.1)	1,197.6
Total revenues	—	—	—	12,595.3	(2.1)	12,593.2
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	9,422.7	—	9,422.7
Operating expenses	(0.6)	—	—	1,338.3	(2.1)	1,335.6
Gain on sale of assets	—	—	—	(0.6)	—	(0.6)
Operating income	0.6	—	—	1,834.9	—	1,835.5
Equity in net earnings from investments	1,655.6	1,660.5	1,660.5	116.3	(4,934.5)	158.4
Other income (expense), net	29.6	315.1	315.1	(36.0)	(630.2)	(6.4)
Interest expense, net	(179.4)	(315.1)	(315.1)	(290.2)	630.2	(469.6)
Income before income taxes	1,506.4	1,660.5	1,660.5	1,625.0	(4,934.5)	1,517.9
Income taxes	(354.7)	—	—	(8.2)	—	(362.9)
Net income	1,151.7	1,660.5	1,660.5	1,616.8	(4,934.5)	1,155.0
Less: Net income attributable to noncontrolling interests	—	—	—	3.3	—	3.3
Net income attributable to ONEOK	1,151.7	1,660.5	1,660.5	1,613.5	(4,934.5)	1,151.7
Less: Preferred stock dividends	1.1	—	—	—	—	1.1
Net income available to common shareholders	$ 1,150.6	$ 1,660.5	$ 1,660.5	$ 1,613.5	$ (4,934.5)	$ 1,150.6
Net income	$ 1,151.7	$ 1,660.5	$ 1,660.5	$ 1,616.8	$ (4,934.5)	$ 1,155.0
Other comprehensive income (loss), net of tax	(39.5)	101.1	85.9	62.6	(171.7)	38.4
Comprehensive income	1,112.2	1,761.6	1,746.4	1,679.4	(5,106.2)	1,193.4
Less: Comprehensive income attributable to noncontrolling interests	—	—	—	3.3	—	3.3
Comprehensive income attributable to ONEOK	$ 1,112.2	$ 1,761.6	$ 1,746.4	$ 1,676.1	$ (5,106.2)	$ 1,190.1

	Year Ended December 31, 2017					
	Parent Issuer & Guarantor	**Subsidiary Issuer & Guarantor**	**Guarantor Subsidiary**	**Combined Non-Guarantor Subsidiaries**	**Consolidating Entries and Other**	**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	17.8	—	9.2	1,204.0	(2.0)	1,229.0
Impairment of long-lived assets	—	—	—	16.0	—	16.0
Gain on sale of assets	—	—	—	(0.9)	—	(0.9)
Operating income	(17.8)	—	(9.2)	1,418.8	—	1,391.8
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	(12.3)	353.1	353.1	(8.0)	(706.2)	(20.3)
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
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	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

Condensed Consolidating Balance Sheets

	December 31, 2019					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
Assets	(*Millions of dollars*)					
Current assets						
Cash and cash equivalents	$ 21.0	$ —	$ —	$ —	$ —	$ 21.0
Accounts receivable, net	—	—	—	835.1	—	835.1
Materials and supplies	—	—	—	201.7	—	201.7
Natural gas and NGLs in storage	—	—	—	304.9	—	304.9
Other current assets	12.4	—	—	95.2	—	107.6
Total current assets	33.4	—	—	1,436.9	—	1,470.3
Property, plant and equipment						
Property, plant and equipment	166.6	—	—	21,884.9	—	22,051.5
Accumulated depreciation and amortization	99.5	—	—	3,603.3	—	3,702.8
Net property, plant and equipment	67.1	—	—	18,281.6	—	18,348.7
Investments and other assets						
Investments	6,732.6	4,101.4	11,466.3	769.9	(22,208.4)	861.8
Intercompany notes receivable	8,950.9	6,903.2	—	—	(15,854.1)	—
Other assets	139.9	—	—	992.1	(0.7)	1,131.3
Total investments and other assets	15,823.4	11,004.6	11,466.3	1,762.0	(38,063.2)	1,993.1
Total assets	$ 15,923.9	$ 11,004.6	$ 11,466.3	$ 21,480.5	$ (38,063.2)	$ 21,812.1
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$ —	$ —	$ —	$ 7.7	$ —	$ 7.7
Short-term borrowings	220.0	—	—	—	—	220.0
Accounts payable	23.8	—	—	1,186.1	—	1,209.9
Other current liabilities	243.8	63.3	—	275.6	—	582.7
Total current liabilities	487.6	63.3	—	1,469.4	—	2,020.3
Intercompany payables	—	—	7,364.9	8,489.2	(15,854.1)	—
Long-term debt, excluding current maturities	8,421.1	4,045.1	—	13.5	—	12,479.7
Deferred credits and other liabilities						
Deferred income taxes	417.1	—	—	119.7	(0.7)	536.1
Other deferred credits	372.1	—	—	177.9	—	550.0
Total deferred credits and other liabilities	789.2	—	—	297.6	(0.7)	1,086.1
Commitments and contingencies						
Equity	6,226.0	6,896.2	4,101.4	11,210.8	(22,208.4)	6,226.0
Total liabilities and equity	$ 15,923.9	$ 11,004.6	$ 11,466.3	$ 21,480.5	$ (38,063.2)	$ 21,812.1

	December 31, 2018					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
Assets			(*Millions of dollars*)			
Current assets						
Cash and cash equivalents	$ 12.0	$ —	$ —	$ —	$ —	$ 12.0
Accounts receivable, net	—	—	—	819.0	—	819.0
Materials and supplies	—	—	—	141.2	—	141.2
Natural gas and NGLs in storage	—	—	—	296.7	—	296.7
Other current assets	29.1	—	—	100.6	—	129.7
Total current assets	41.1	—	—	1,357.5	—	1,398.6
Property, plant and equipment						
Property, plant and equipment	145.5	—	—	17,885.5	—	18,031.0
Accumulated depreciation and amortization	92.0	—	—	3,172.3	—	3,264.3
Net property, plant and equipment	53.5	—	—	14,713.2	—	14,766.7
Investments and other assets						
Investments	6,153.5	3,548.1	9,721.6	791.1	(19,245.1)	969.2
Intercompany notes receivable	5,308.6	7,701.5	1,528.0	—	(14,538.1)	—
Other assets	115.9	—	—	982.3	(1.0)	1,097.2
Total investments and other assets	11,578.0	11,249.6	11,249.6	1,773.4	(33,784.2)	2,066.4
Total assets	$ 11,672.6	$ 11,249.6	$ 11,249.6	$ 17,844.1	$ (33,784.2)	$ 18,231.7
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$ —	$ 500.0	$ —	$ 7.7	$ —	$ 507.7
Accounts payable	31.3	—	—	1,085.0	—	1,116.3
Other current liabilities	123.2	81.0	—	280.2	—	484.4
Total current liabilities	154.5	581.0	—	1,372.9	—	2,108.4
Intercompany payables	—	—	7,701.5	6,836.6	(14,538.1)	—
Long-term debt, excluding current maturities	4,510.7	4,341.4	—	21.2	—	8,873.3
Deferred credits and other liabilities						
Deferred income taxes	112.3	—	—	108.4	(1.0)	219.7
Other deferred credits	315.6	—	—	135.2	—	450.8
Total deferred credits and other liabilities	427.9	—	—	243.6	(1.0)	670.5
Commitments and contingencies						
Equity	6,579.5	6,327.2	3,548.1	9,369.8	(19,245.1)	6,579.5
Total liabilities and equity	$ 11,672.6	$ 11,249.6	$ 11,249.6	$ 17,844.1	$ (33,784.2)	$ 18,231.7

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2019					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
	(*Millions of dollars*)					
Operating activities						
Cash provided by operating activities	$ 1,010.1	$ 1,332.9	$ 68.9	$ 2,198.9	$ (2,664.0)	$ 1,946.8
Investing activities						
Capital expenditures	(25.6)	—	—	(3,822.7)	—	(3,848.3)
Other investing activities	—	—	74.6	4.9	—	79.5
Cash provided by (used in) investing activities	(25.6)	—	74.6	(3,817.8)	—	(3,768.8)
Financing activities						
Dividends paid	(1,457.6)	(1,332.0)	(1,332.0)	—	2,664.0	(1,457.6)
Intercompany borrowings (advances), net	(3,618.6)	801.8	1,188.5	1,628.3	—	—
Short-term borrowings, net	220.0	—	—	—	—	220.0
Issuance of long-term debt, net of discounts	4,185.4	—	—	—	—	4,185.4
Repayment of long-term debt	(249.6)	(800.0)	—	(7.7)	—	(1,057.3)
Issuance of common stock	29.0	—	—	—	—	29.0
Other, net	(84.1)	(2.7)	—	(1.7)	—	(88.5)
Cash provided by (used in) financing activities	(975.5)	(1,332.9)	(143.5)	1,618.9	2,664.0	1,831.0
Change in cash and cash equivalents	9.0	—	—	—	—	9.0
Cash and cash equivalents at beginning of period	12.0	—	—	—	—	12.0
Cash and cash equivalents at end of period	$ 21.0	$ —	$ —	$ —	$ —	$ 21.0

	Year Ended December 31, 2018					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$ 1,325.1	$ 1,344.7	$ 67.9	$ 2,113.0	$ (2,664.0)	$ 2,186.7
Investing activities						
Capital expenditures	(18.8)	—	—	(2,122.7)	—	(2,141.5)
Other investing activities	—	—	15.3	11.3	—	26.6
Cash provided by (used in) investing activities	(18.8)	—	15.3	(2,111.4)	—	(2,114.9)
Financing activities						
Dividends paid	(1,335.1)	(1,332.0)	(1,332.0)	—	2,664.0	(1,335.1)
Distributions to noncontrolling interests	—	—	—	(3.5)	—	(3.5)
Intercompany borrowings (advances), net	(2,154.4)	912.3	1,248.8	(6.7)	—	—
Repayment of short-term borrowings, net	(614.7)	—	—	—	—	(614.7)
Issuance of long-term debt, net of discounts	1,795.8	—	—	—	—	1,795.8
Repayment of long-term debt	—	(925.0)	—	(7.7)	—	(932.7)
Issuance of common stock	1,204.0	—	—	—	—	1,204.0
Acquisition of noncontrolling interests	(195.0)	—	—	—	—	(195.0)
Other, net	(32.1)	—	—	16.3	—	(15.8)
Cash used in financing activities	(1,331.5)	(1,344.7)	(83.2)	(1.6)	2,664.0	(97.0)
Change in cash and cash equivalents	(25.2)	—	—	—	—	(25.2)
Cash and cash equivalents at beginning of period	37.2	—	—	—	—	37.2
Cash and cash equivalents at end of period	$ 12.0	$ —	$ —	$ —	$ —	$ 12.0

	Year Ended December 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries and Other	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, net	(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

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 Rules 13a-15(e) and 15d-15(e) 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, our management concluded that our internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019, 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, 2019, 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 2020 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 2020 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 2020 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Committee Procedures

Information concerning the Nominating Committee procedures is set forth in our 2020 definitive Proxy Statement and is incorporated herein by this reference.

Audit Committee

Information concerning the Audit Committee is set forth in our 2020 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 2020 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2020 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 2020 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 2020 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, 2019:

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)	2,076,295	$ 64.33	8,960,329
Equity compensation plans not approved by security holders (2)	350,029	$ 75.67	—
Total	2,426,324	$ 65.96	8,960,329

(1) - Includes shares granted under our Employee Stock Purchase Plan and Employee Stock Award Program and restricted stock incentive unit awards and performance unit awards granted under our former Long-Term Incentive Plan, our former Equity Compensation Plan and our Equity Incentive Plan. For a brief description of the material features of these plans, see Note J of the Notes to Consolidated Financial Statements in this Annual Report. Column (a) includes shares based on 100% of the performance units vesting at the end of the three-year performance period. Column (c) includes 1,211,710, 133,075 and 7,615,544 shares available for future issuance under our Employee Stock Purchase Plan, Employee Stock Award Program and Equity Incentive Plan, respectively.

(2) - Includes our NQDC Plan, Deferred Compensation Plan for Non-Employee Directors and our former Stock Compensation Plan for Non-Employee Directors. For a brief description of the material features of these plans, see Note J of the Notes to Consolidated Financial Statements in this Annual Report.

(3) - Compensation deferred into our common stock under our former Equity Compensation Plan and our 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 $75.67, which represents the 2019 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 2020 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 2020 definitive Proxy Statement and is incorporated herein by this reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(1) Financial Statements		Page No.
(a)	Report of Independent Registered Public Accounting Firm	54-55
(b)	Consolidated Statements of Income for the years ended December 31, 2019, 2018 and 2017	56
(c)	Consolidated Statements of Comprehensive Income for the years ended December 31, 2019, 2018 and 2017	57
(d)	Consolidated Balance Sheets as of December 31, 2019 and 2018	58-59
(e)	Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017	61
(f)	Consolidated Statements of Changes in Equity for the years ended December 31, 2019, 2018 and 2017	62-63
(g)	Notes to Consolidated Financial Statements	64-111

(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	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)).
3.1	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 September 20, 2018 (File No. 1-13643)).
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, with respect to the 6.50% Senior Insured Quarterly Notes due 2028 (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, with respect to the 6.875% Debentures due 2028 (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% 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% 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% 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% 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	Certificate of Designation, Preferences and Rights of Series E Non-Voting Perpetual Preferred Stock of ONEOK, Inc. filed April 20, 2017 (incorporated by reference from Exhibit No. 3.1 to ONEOK, Inc.'s Current Report on Form 8-K filed April 20, 2017 (File No. 1-13643)).
4.15	Third Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank, as trustee, with respect to the 6.00% Senior Notes due 2035 (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% 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% 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% 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% 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	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% 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)).
4.22	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% 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)).
4.23	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% 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)).
4.24	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% 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)).

4.25	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)).
4.26	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% 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)).
4.27	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)).
4.28	First Supplemental Indenture, dated January 26, 2012, among ONEOK, Inc. and U.S. Bank National Association, as trustee, with respect to the 4.25% 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)).
4.29	Second Supplemental Indenture, dated August 21, 2015, between ONEOK, Inc. and U.S. Bank National Association, as trustee, with respect to the 7.50% 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)).
4.30	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, with respect to the 6.00% Senior Notes due 2035 (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)).
4.31	Sixth Supplemental Indenture, dated as of July 2, 2018, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.55% Senior Notes due 2028 (incorporated by reference from Exhibit No. 4.1 to ONEOK, Inc.'s Current Report on Form 8-K filed July 2, 2018 (File No. 1-13643)).
4.32	Seventh Supplemental Indenture, dated as of July 2, 2018, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 5.20% Senior Notes due 2048 (incorporated by reference from Exhibit No. 4.2 to ONEOK, Inc.'s Current Report on Form 8-K filed July 2, 2018 (File No. 1-13643)).
4.33	Eighth Supplemental Indenture, dated as of March 13, 2019, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.35% Senior Notes due 2029 (incorporated by reference from Exhibit No. 4.2 to ONEOK, Inc.'s Current Report on Form 8-K filed March 13, 2019 (File No. 1-13643)).
4.34	Ninth Supplemental Indenture, dated as of March 13, 2019, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 5.20% Senior Notes due 2048 (incorporated by reference from Exhibit No. 4.3 to ONEOK, Inc.'s Current Report on Form 8-K filed March 13, 2019 (File No. 1-13643)).
4.35	Tenth Supplemental Indenture, dated as of August 15, 2019, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 2.75% Senior Notes due 2024 (incorporated by reference from Exhibit No. 4.1 to ONEOK, Inc.'s Current Report on Form 8-K filed August 15, 2019 (File No. 1-13643)).
4.36	Eleventh Supplemental Indenture, dated as of August 15, 2019, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 3.40% Senior Notes due 2029 (incorporated by reference from Exhibit No. 4.2 to ONEOK, Inc.'s Current Report on Form 8-K filed August 15, 2019 (File No. 1-13643)).

4.37	Twelfth Supplemental Indenture, dated as of August 15, 2019, among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.45% Senior Notes due 2049 (incorporated by reference from Exhibit No. 4.3 to ONEOK, Inc.'s Current Report on Form 8-K filed August 15, 2019 (File No. 1-13643)).
4.38	Description of securities.
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 the 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	Extension Agreement, dated as of June 18, 2018, 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 No. 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed June 18, 2018 (File No. 1-13643)).
10.13	First Amendment and Extension Agreement, dated as of May 24, 2019, 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 No. 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed May 29, 2019 (File No. 1-13643)).
10.14	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)).
10.15	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)).
10.16	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 the 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)).
10.17	Form of 2018 Restricted Unit Stock Award Agreement dated February 21, 2018 (incorporated by reference to Exhibit 10.17 to ONEOK, Inc.'s Annual Report on Form 10-K filed on February 27, 2018 (File No. 1-13643)).
10.18	Form of 2018 Performance Unit Award Agreement dated February 21, 2018 (incorporated by reference to Exhibit 10.18 to ONEOK, Inc.'s Annual Report on Form 10-K filed on February 27, 2018 (File No. 1-13643)).
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	Term Loan Agreement, dated as of November 19, 2018, among ONEOK, Inc., Mizuho Bank, Ltd., as administrative agent and a lender, and the other lenders parties thereto (incorporated by reference from Exhibit No. 10.1 to ONEOK, Inc.'s Current Report on Form 8-K filed November 21, 2018 (File No. 1-13643)).
10.24	Guaranty Agreement, dated as of November 19, 2018, by ONEOK Partners Intermediate Limited Partnership and ONEOK Partners, L.P. in favor of Mizuho Bank, Ltd., as administrative agent, under the above-referenced Term Loan Agreement (incorporated by reference from Exhibit No. 10.2 to ONEOK, Inc.'s Current Report on Form 8-K filed November 21, 2018 (File No. 1-13643)).
10.25	ONEOK, Inc. Equity Incentive Plan (incorporated by reference to Appendix A to ONEOK, Inc.'s definitive proxy statement on Schedule 14A filed on April 5, 2018 (File No. 1-13643)).
10.26	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)).
10.27	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)).
10.28	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)).
10.29	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)).
10.30	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)).
10.31	Form of 2019 Restricted Unit Award Agreement, dated February 20, 2019 (incorporated by reference to Exhibit 10.54 to ONEOK, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2018, filed February 26, 2019 (File No. 1-13643)).
10.32	Form of 2019 Performance Unit Award Agreement, dated February 20, 2019 (incorporated by reference to Exhibit 10.55 to ONEOK Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2018, filed February 26, 2019 (File No. 1-13643)).
10.33	Form of 2016 Restricted Unit Award Agreement, dated 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)).
10.34	Form of 2016 Performance Unit Award Agreement, dated 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)).
10.35	Form of 2020 Restricted Unit Award Agreement.

10.36	Form of 2020 Performance Unit Award Agreement.
10.37	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)).
10.38	Form of First Amendment to 2019 Performance Unit Award Agreement.
10.39	Form of First Amendment to 2018 Performance Unit Award Agreement.
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 III 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 III 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	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definitions Document.
101.LAB	Inline XBRL Taxonomy Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted in Inline XBRL and contained in Exhibit 101).

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, 2019, 2018 and 2017; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2019, 2018 and 2017; (iv) Consolidated Balance Sheets at December 31, 2019 and 2018; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018 and 2017; (vi) Consolidated Statements of Changes in Equity for the years ended December 31, 2019, 2018 and 2017; and (vii) Notes to Consolidated Financial Statements.

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 25, 2020

By: /s/ Walter S. Hulse III
Walter S. Hulse III
Chief Financial Officer, Treasurer 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 25th day of February 2020.

/s/ John W. Gibson John W. Gibson Chairman of the Board	/s/ Terry K. Spencer Terry K. Spencer President, Chief Executive Officer and Director
/s/ Walter S. Hulse III Walter S. Hulse III Chief Financial Officer, Treasurer and Executive Vice President, Strategic Planning and Corporate Affairs	/s/ Mary M. Spears Mary M. Spears Vice President and Chief Accounting Officer
/s/ Brian L. Derksen Brian L. Derksen Director	/s/ Julie H. Edwards Julie H. Edwards Director
/s/ Mark W. Helderman Mark W. Helderman Director	/s/ Randall J. Larson Randall J. Larson Director
/s/ Steven J. Malcolm Steven J. Malcolm Director	/s/ Jim W. Mogg Jim W. Mogg Director
/s/ Pattye L. Moore Pattye L. Moore Director	/s/ Gary D. Parker Gary D. Parker Director
/s/ Eduardo A. Rodriguez 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

Mark W. Helderman
Retired Managing Director and Co-Portfolio Manager, Sasco Capital Inc.
Cleveland, Ohio

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
Former 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, 2020

Terry K. Spencer, 60
President and Chief Executive Officer

Robert F. Martinovich, 62
Executive Vice President and Chief Administrative Officer

Walter S. Hulse III, 56
Chief Financial Officer, Treasurer and Executive Vice President,
Strategic Planning and Corporate Affairs

Kevin L. Burdick, 55
Executive Vice President and Chief Operating Officer

Stephen B. Allen, 46
Senior Vice President, General Counsel and Assistant Secretary

Sheridan C. Swords, 50
Senior Vice President, Natural Gas Liquids

Charles M. Kelley, 61
Senior Vice President, Natural Gas

Mary M. Spears, 40
Vice President and Chief Accounting Officer

Eric Grimshaw, 67
Vice President, Associate General Counsel and Secretary

CORPORATE INFORMATION

ANNUAL MEETING

The 2020 annual meeting of shareholders will be held Wednesday, May 20, 2020, 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 (positive)

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

MIX
Paper from responsible sources
FSC® C103375

100 West Fifth Street
Tulsa, Oklahoma 74103-4298

Post Office Box 871
Tulsa, Oklahoma 74102-0871

www.oneok.com

ONEOK