ONEOK INC /NEW/
Form 10-Q
November 01, 2017

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

FORM 10-Q

X Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2017.
OR
___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __________ to __________.

Commission file number 001-13643

ONEOK, Inc.
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes X No __

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

Indicate by check mark 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.

Large accelerated filer X	Accelerated filer __	Non-accelerated filer __
Smaller reporting company__	Emerging growth company__	

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

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

On October 23, 2017, the Company had 383,436,687 shares of common stock outstanding.

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

The statements in this Quarterly Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "pla "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other w 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 2, Management's Discussion and Analysis of Financial Condition and Results of Operations "Forward-Looking Statements," in this Quarterly Report and under Part I, Item 1A, "Risk Factors," in our Annual Report.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.oneok.com) copies of our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, 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 and Director Independence Guidelines are also available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

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

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GLOSSARY

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

2017 Credit Agreement	ONEOK’s $2.5 billion revolving credit agreement, effective June 30, 2017
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2016
ASU	Accounting Standards Update
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CFTC	U.S. Commodity Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
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.
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
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
Moody’s	Moody’s Investors Service, Inc.
NGL(s)	Natural gas liquid(s)
NGL products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ONEOK	ONEOK, Inc.
ONEOK Credit Agreement	ONEOK’s $300 million amended and restated revolving credit agreement, which terminated June 30, 2017
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners Credit Agreement	ONEOK Partners’ $2.4 billion amended and restated revolving credit agreement, which terminated June 30, 2017
OPIS	Oil Price Information Service
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
POP	Percent of Proceeds
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
Roadrunner	Roadrunner Gas Transmission, LLC, a 50 percent-owned joint venture
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
Series E Preferred Stock	Series E Non-Voting, Perpetual Preferred Stock, par value $0.01 per share

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STACK	Sooner Trend Anadarko Canadian Kingfisher, an area in the Anadarko Basin in Oklahoma
Term Loan Agreement	ONEOK Partners' senior unsecured three-year $1.0 billion term loan agreement dated January 8, 2016, as amended
West Texas LPG	West Texas LPG Pipeline Limited Partnership and Mesquite Pipeline
WTI	West Texas Intermediate
WTLPG	West Texas LPG Pipeline Limited Partnership, an 80 percent-owned joint venture
XBRL	eXtensible Business Reporting Language

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ONEOK Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Unaudited)	2017	2016	2017	2016
	(Thousands of dollars, except per share amounts)			
Revenues				
Commodity sales	$2,322,534	$1,840,523	$6,700,260	$4,757,306
Services	583,832	517,384	1,681,489	1,509,167
Total revenues	2,906,366	2,357,907	8,381,749	6,266,473
Cost of sales and fuel (exclusive of items shown separately below)	2,229,416	1,751,593	6,464,281	4,474,654
Operations and maintenance	182,409	165,664	540,679	488,476
Depreciation and amortization	102,298	98,550	302,566	292,275
Impairment of long-lived assets	15,970	—	15,970	—
General taxes	24,641	18,487	76,098	64,529
Gain on sale of assets	(274)	(5,744)	(904)	(9,537)
Operating income	351,906	329,357	983,059	956,076
Equity in net earnings from investments (Note J)	40,058	35,155	118,985	100,441
Impairment of equity investments (Note J)	(4,270)	—	(4,270)	—
Allowance for equity funds used during construction	40	—	75	208
Other income	3,296	4,242	11,670	9,351
Other expense	(838)	(710)	(23,431)	(2,288)
Interest expense (net of capitalized interest of $1,068, $3,806, $4,254, and $9,265, respectively)	(126,533)	(118,240)	(361,468)	(355,463)
Income before income taxes	263,659	249,804	724,620	708,325
Income taxes	(97,128)	(55,012)	(195,913)	(157,536)
Income from continuing operations	166,531	194,792	528,707	550,789
Income (loss) from discontinued operations, net of tax	—	(576)	—	(1,755)
Net income	166,531	194,216	528,707	549,034
Less: Net income attributable to noncontrolling interests	789	102,072	203,911	287,500
Net income attributable to ONEOK	165,742	92,144	324,796	261,534
Less: Preferred stock dividends	276	—	493	—
Net income available to common shareholders	$165,466	$92,144	$324,303	$261,534
Amounts available to common shareholders:				
Income from continuing operations	$165,466	$92,720	$324,303	$263,289
Income (loss) from discontinued operations	—	(576)	—	(1,755)
Net income	$165,466	$92,144	$324,303	$261,534
Basic earnings per common share:				
Income from continuing operations (Note H)	$0.43	$0.44	$1.21	$1.25
Income (loss) from discontinued operations	—	—	—	(0.01)
Net income	$0.43	$0.44	$1.21	$1.24
Diluted earnings per common share:				
Income from continuing operations (Note H)	$0.43	$0.44	$1.20	$1.24
Income (loss) from discontinued operations	—	(0.01)	—	(0.01)

Net income	$0.43	$0.43	$1.20	$1.23
Average shares (thousands)				
Basic	380,907	211,309	268,108	211,038
Diluted	383,419	212,870	270,349	212,123
Dividends declared per share of common stock	$0.745	$0.615	$1.975	$1.845

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
	(Thousands of dollars)			
Net income	$166,531	$194,216	$528,707	$549,034
Other comprehensive income (loss), net of tax				
Unrealized gains (losses) on derivatives, net of tax of $12,217, $(1,301), $8,689 and $15,033, respectively	(20,620)	7,237	(1,287)	(83,580)
Realized (gains) losses on derivatives recognized in net income, net of tax of $(7,671), $(811), $(13,077) and $1,658, respectively	13,062	3,083	40,272	(13,496)
Change in pension and postretirement benefit plan liability, net of tax of $(1,360), $(1,035), $(4,081) and $(3,105) respectively.	2,041	1,553	6,122	4,658
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax of $100, $108, $288 and $1,840, respectively	(169)	(600)	(1,214)	(10,231)
Total other comprehensive income (loss), net of tax	(5,686)	11,273	43,893	(102,649)
Comprehensive income	160,845	205,489	572,600	446,385
Less: Comprehensive income attributable to noncontrolling interests	789	108,450	234,937	211,960
Comprehensive income attributable to ONEOK	$160,056	$97,039	$337,663	$234,425

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(Unaudited)	September 30, 2017	December 31, 2016
Assets	(Thousands of dollars)	
Current assets		
Cash and cash equivalents	$11,676	$248,875
Accounts receivable, net	939,595	872,430
Materials and supplies	77,366	60,912
Natural gas and natural gas liquids in storage	314,266	140,034
Commodity imbalances	111,766	60,896
Other current assets	64,196	45,986
Assets of discontinued operations	—	551
Total current assets	1,518,865	1,429,684
Property, plant and equipment		
Property, plant and equipment	15,364,289	15,078,497
Accumulated depreciation and amortization	2,785,682	2,507,094
Net property, plant and equipment	12,578,607	12,571,403
Investments and other assets		
Investments in unconsolidated affiliates	1,013,702	958,807
Goodwill and intangible assets	996,435	1,005,359
Deferred income taxes	474,967	—
Other assets	182,265	162,998
Assets of discontinued operations	—	10,500
Total investments and other assets	2,667,369	2,137,664
Total assets	$16,764,841	$16,138,751

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

(Unaudited)	September 30, 2017	December 31, 2016
Liabilities and equity	(Thousands of dollars)	
Current liabilities		
Current maturities of long-term debt (Note E)	$432,650	$410,650
Short-term borrowings (Note E)	932,250	1,110,277
Accounts payable	922,820	874,731
Commodity imbalances	189,512	142,646
Accrued interest	97,023	112,514
Other current liabilities	166,825	166,042
Liabilities of discontinued operations	—	19,841
Total current liabilities	2,741,080	2,836,701
Long-term debt, excluding current maturities (Note E)	8,092,000	7,919,996
Deferred credits and other liabilities		
Deferred income taxes	76,262	1,623,822
Other deferred credits	339,116	321,846
Liabilities of discontinued operations	—	7,471
Total deferred credits and other liabilities	415,378	1,953,139
Commitments and contingencies (Note K)		
Equity (Note F)		
ONEOK shareholders' equity:		
Preferred stock, $0.01 par value: issued 20,000 shares at September 30, 2017, and no shares at December 31, 2016	—	—
Common stock, $0.01 par value: authorized 1,200,000,000 shares, issued 415,913,504 shares and outstanding 381,285,028 shares at September 30, 2017; authorized 600,000,000 shares, issued 245,811,180 shares and outstanding 210,681,661 shares at December 31, 2016	4,159	2,458
Paid-in capital	6,418,038	1,234,314
Accumulated other comprehensive loss (Note G)	(181,771)	(154,350)
Retained earnings	—	—
Treasury stock, at cost: 34,628,476 shares at September 30, 2017, and 35,129,519 shares at December 31, 2016	(880,931)	(893,677)
Total ONEOK shareholders' equity	5,359,495	188,745
Noncontrolling interests in consolidated subsidiaries	156,888	3,240,170
Total equity	5,516,383	3,428,915
Total liabilities and equity	$16,764,841	$16,138,751

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)	Nine Months Ended September 30, 2017	2016
	(Thousands of dollars)	
Operating activities		
Net income	$528,707	$549,034
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	302,566	292,275
Impairment charges	20,240	—
Noncash contribution of preferred stock, net of tax	12,600	—
Equity in net earnings from investments	(118,985)	(100,441)
Distributions received from unconsolidated affiliates	124,517	106,381
Deferred income taxes	186,584	157,819
Share-based compensation expense	19,688	31,112
Pension and postretirement benefit expense, net of contributions	818	8,270
Allowance for equity funds used during construction	(75)	(208)
Gain on sale of assets	(904)	(9,537)
Changes in assets and liabilities:		
Accounts receivable	(33,224)	(145,430)
Natural gas and natural gas liquids in storage	(174,232)	(89,685)
Accounts payable	82,174	138,198
Commodity imbalances, net	(4,004)	55,109
Settlement of exit activities liabilities	(8,127)	(16,211)
Accrued interest	(15,491)	(24,906)
Risk-management assets and liabilities	34,534	(48,695)
Other assets and liabilities, net	(21,390)	18,943
Cash provided by operating activities	935,996	922,028
Investing activities		
Capital expenditures (less allowance for equity funds used during construction)	(330,431)	(491,528)
Contributions to unconsolidated affiliates	(87,653)	(55,177)
Distributions received from unconsolidated affiliates in excess of cumulative earnings	21,577	43,018
Proceeds from sale of assets	1,910	19,099
Cash used in investing activities	(394,597)	(484,588)
Financing activities		
Dividends paid	(543,445)	(388,103)
Distributions to noncontrolling interests	(275,060)	(412,539)
Borrowing (repayment) of short-term borrowings, net	(178,027)	147,160
Issuance of long-term debt, net of discounts	1,190,067	1,000,000
Debt financing costs	(11,340)	(2,770)
Repayment of long-term debt	(992,864)	(656,117)
Issuance of common stock	45,849	14,948
Other	(13,778)	—
Cash used in financing activities	(778,598)	(297,421)
Change in cash and cash equivalents	(237,199)	140,019
Change in cash and cash equivalents included in discontinued operations	—	(228)
Change in cash and cash equivalents from continuing operations	(237,199)	139,791

Cash and cash equivalents at beginning of period	248,875	97,619
Cash and cash equivalents at end of period	$11,676	$237,410

See accompanying Notes to Consolidated Financial Statements.

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

(Unaudited)	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	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note G)	—	—	—	—	—
Common stock issued	1,181,493	—	12	—	68,032
Preferred stock issued	—	20,000	—	—	20,000
Common stock dividends - $1.975 per share (Note F)	—	—	—	—	(144,912)
Preferred stock dividends (Note F)	—	—	—	—	(493)
Distributions to noncontrolling interests	—	—	—	—	—
Acquisition of ONEOK Partners' noncontrolling interests (Note B)	168,920,831	—	1,689	—	5,228,580
Other	—	—	—	—	12,517
September 30, 2017	415,913,504	20,000	$4,159	$ —	$6,418,038

(Unaudited)	ONEOK Shareholders' Equity Common Stock Issued	Preferred Stock Issued	Common Stock	Preferred Stock	Paid-in Capital
	(Shares)		(Thousands of dollars)		
January 1, 2016	245,811,180	—	$2,458	$ —	$1,378,444
Net income	—	—	—	—	—
Other comprehensive income (loss)	—	—	—	—	—
Common stock issued	—	—	—	—	(531)
Common stock dividends - $1.845 per share (Note F)	—	—	—	—	(126,569)
Distributions to noncontrolling interests	—	—	—	—	—
Other	—	—	—	—	12,697
September 30, 2016	245,811,180	—	$2,458	$ —	$1,264,041

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

(Unaudited)	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	—	73,368	—	—	73,368
Net income	—	324,796	—	203,911	528,707
Other comprehensive income (loss) (Note G)	12,867	—	—	31,026	43,893
Common stock issued	—	—	12,746	—	80,790
Preferred stock issued	—	—	—	—	20,000
Common stock dividends - $1.975 per share (Note F)	—	(398,164)	—	—	(543,076)
Preferred stock dividends (Note F)	—	—	—	—	(493)
Distributions to noncontrolling interests	—	—	—	(275,060)	(275,060)
Acquisition of ONEOK Partners' noncontrolling interests (Note B)	(40,288)	—	—	(3,043,519)	2,146,462
Other	—	—	—	360	12,877
September 30, 2017	$(181,771)	$ —	$(880,931)	$ 156,888	$5,516,383

(Unaudited)	ONEOK Shareholders' Equity				
	Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
	(Thousands of dollars)				
January 1, 2016	$(127,242)	$ —	$(917,862)	$ 3,430,538	$3,766,336
Net income	—	261,534	—	287,500	549,034
Other comprehensive income (loss)	(27,109)	—	—	(75,540)	(102,649)
Common stock issued	—	—	20,010	—	19,479
Common stock dividends - $1.845 per share (Note F)	—	(261,534)	—	—	(388,103)
Distributions to noncontrolling interests	—	—	—	(412,539)	(412,539)
Other	—	—	—	(4,041)	8,656
September 30, 2016	$(154,351)	$ —	$(897,852)	$ 3,225,918	$3,440,214

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our accompanying unaudited consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC. These statements have been prepared in accordance with GAAP and reflect all adjustments that, in our opinion, are necessary for a fair statement of the results for the interim periods presented. All such adjustments are of a normal recurring nature. The 2016 year-end consolidated balance sheet data was derived from our audited financial statements but does not include all disclosures required by GAAP. Certain reclassifications have been made in the prior-year financial statements to conform to the current-year presentation. These unaudited consolidated financial statements should be read in conjunction with our audited consolidated financial statements in our Annual Report and our Current Report on Form 8-K filed on July 6, 2017, which updates Item 8 in our Annual Report.

Our significant accounting policies are consistent with those disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report, except as described below.

Merger Transaction - On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own. See Note B for additional information, including a discussion of the impact of the Merger Transaction on our Consolidated Financial Statements.

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

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

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that were adopted			
ASU 2015-11, “Inventory (Topic 330): Simplifying the Measurement of Inventory”	The standard requires that inventory, excluding inventory measured using last-in, first-out (LIFO) or the retail inventory method, be measured at the lower of cost or net realizable value.	First quarter 2017	As a result of adopting this guidance, we updated our accounting policy for inventory valuation accordingly. The financial impact of adopting this guidance was not material.
ASU 2016-05, “Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships”	The standard clarifies that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument under Topic 815 does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue	First quarter 2017	The impact of adopting this standard was not material.

	to be met.		
ASU 2016-06, “Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments”	The standard clarifies the requirements for assessing whether a contingent call (put) option that can accelerate the payment of principal on a debt instrument is clearly and closely related to its debt host.	First quarter 2017	The impact of adopting this standard was not material.
ASU 2016-09, “Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting”	The standard provides simplified accounting for share-based payment transactions in relation to income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.	First quarter 2017	As a result of adopting this guidance, we recorded an adjustment increasing beginning retained earnings and deferred tax assets in the first quarter 2017 of approximately $73 million to recognize previously unrecognized cumulative excess tax benefits related to share-based payments on a modified retrospective basis. Beginning in January 2017, all share-based payment tax effects are recorded in earnings. The other effects of adopting this standard were not material.

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that are not yet adopted			
ASU 2014-09, “Revenue from Contracts with Customers (Topic 606)”	The standard outlines the principles an entity must apply to measure and recognize revenue for entities that enter into contracts to provide goods or services to their customers. The core principle is that an entity should recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services to a customer. The amendment also requires more extensive disaggregated revenue disclosures in interim and annual financial statements.	First quarter 2018	We expect to adopt this standard on January 1, 2018, using the modified retrospective method. We have not completed our analysis to quantify the cumulative effect of adoption adjustment to retained earnings, but do not expect it to be material. For many of our contracts, we do not expect material changes in our accounting policies or revenue recognition. However, under Topic 606, we expect that a significant portion of services revenues will be presented as reduction of cost of sales and fuel, for certain midstream service contracts where we also purchase raw natural gas or unfractionated NGLs. Under Topic 606, these contracts are considered supplier contracts rather than contracts with customers. We have not completed our analysis to quantify the amount expected to be reclassified to cost of sales and fuel from services revenue, but expect it to be material. We do not believe the adoption of Topic 606 will have a material impact on operating income or net income. We are developing required disclosures and expect to disaggregate revenues on a segment basis similar to our current presentation in Management’s Discussion and Analysis. We expect our disclosure of unsatisfied performance obligations to relate primarily to firm transportation contracts. We do not expect a material contract asset balance and expect our contract liability balance to include storage contracts that have been prepaid by customers and contributions in aid of construction received from customers.
ASU 2016-01, “Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities”	The standard requires all equity investments, other than those accounted for using the equity method of accounting or those that result in consolidation of the investee, to be measured at fair value with changes in fair value recognized in net income, eliminates the available-for-sale classification for equity securities with readily determinable fair values and eliminates the cost method	First quarter 2018	We do not have any equity investments classified as available-for-sale or accounted for using the cost method, therefore, we do not expect adoption of this standard to have a material impact on us.

	for equity investments without readily determinable fair values.		
ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments"	The standard clarifies the classification of certain cash receipts and cash payments on the statement of cash flows where diversity in practice has been identified.	First quarter 2018	We do not expect the adoption of this standard to materially impact us.
ASU 2017-07, "Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"	The standard requires the service cost component of net benefit cost to be reported in the same line item or items as other compensation costs from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations.	First quarter 2018	We do not expect the adoption of this standard to materially impact us.

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Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that are not yet adopted (continued)			
ASU 2016-02, “Leases (Topic 842)”	The standard requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. It also requires qualitative disclosures along with specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.	First quarter 2019	We are evaluating our current leases and other contracts that may be considered leases under the new standard and the impact on our internal controls, accounting policies and financial statements and disclosures.
ASU 2017-12, “Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities	The standard more closely aligns hedge accounting with companies’ existing risk-management strategies by expanding the strategies eligible for hedge accounting, relaxing the timing requirements of hedge documentation and effectiveness assessments, permitting in certain cases, the use of qualitative assessments on an ongoing basis to assess hedge effectiveness, and requiring new disclosures and presentation.	First Quarter 2019	We are evaluating the timing of adoption and the impact of this standard on us. At adoption, we expect to record a cumulative-effect adjustment to the opening balance of retained earnings and other comprehensive income to eliminate the separate measurement of hedge ineffectiveness, which we do not expect to be material. We expect immaterial changes to disclosures as a result of adopting this standard.
ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments”	The standard requires a financial asset (or a group of financial assets) measured at amortized cost basis to be presented net of the allowance for credit losses to reflect the net carrying value at the amount expected to be collected on the financial asset; and the initial allowance for credit losses for purchased financial assets, including available-for-sale debt securities, to be added to the purchase price rather than being reported as a credit loss expense.	First quarter 2020	We do not expect the adoption of this standard to materially impact us.
ASU 2017-04, “Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment”	The standard simplifies the subsequent measurement of goodwill by eliminating the requirement to calculate the implied fair value of goodwill under step 2. Instead, an entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value. The standard does not change step zero or step 1 assessments.	First quarter 2020	We do not expect the adoption of this standard to materially impact us.

Goodwill Impairment Review - We assess our goodwill for impairment at least annually as of July 1. At July 1, 2017, we assessed qualitative factors to determine whether it was more likely than not that the fair value of each of our reporting units was less than its carrying amount. After assessing qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance), we determined that it was more likely than not that the fair value of each reporting unit was greater than its respective carrying value, that no further testing was necessary and that goodwill was not considered impaired.

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

B. ACQUISITION OF ONEOK PARTNERS

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

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Partners common unitholders instead received cash in lieu of fractional shares. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded.

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

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

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

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

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

C. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

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

	September 30, 2017					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net (b)
	(Thousands of dollars)					
Derivative assets						
Commodity contracts						
Financial contracts	$1,237	$—	$16,629	$17,866	$(17,839)	$27
Interest-rate contracts	—	45,684	—	45,684	—	45,684
Total derivative assets	$1,237	$45,684	$16,629	$63,550	$(17,839)	$45,711
Derivative liabilities						
Commodity contracts						
Financial contracts	$(4,415)	$—	$(39,052)	$(43,467)	$43,268	$(199)
Physical contracts	—	—	(4,083)	(4,083)	—	(4,083)
Total derivative liabilities	$(4,415)	$—	$(43,135)	$(47,550)	$43,268	$(4,282)

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At September 30, 2017, we held no cash and posted $52.8 million of cash with various counterparties, including $25.4 million of cash collateral that is offsetting derivative net liability positions under master-netting arrangements in the table above. The remaining $27.4 million of cash collateral in excess of derivative net liability positions is included in other current assets in our Consolidated Balance Sheets.

(b) - Included in other current assets, other assets, other current liabilities or other deferred credits in our Consolidated Balance Sheets.

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

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

(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Assets (Liabilities)	2017	2016	2017	2016
	(Thousands of dollars)			
Net assets (liabilities) at beginning of period	$750	$(14,021)	$(23,319)	$7,331
Total realized/unrealized gains (losses):				
Included in earnings (a)	(675)	920	(417)	492
Included in other comprehensive income (loss)	(26,581)	3,038	(2,770)	(17,886)
Net assets (liabilities) at end of period	$(26,506)	$(10,063)	$(26,506)	$(10,063)

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

Realized/unrealized gains (losses) include the realization of our derivative contracts through maturity. During the three and nine months ended September 30, 2017 and 2016, gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held at the end of each reporting period were not material.

We recognize transfers into and out of the levels in the fair value hierarchy as of the end of each reporting period. During the three and nine months ended September 30, 2017 and 2016, there were no transfers between levels.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and short-term borrowings is equal to book value due to the short-term nature of these items. Our cash and cash equivalents are 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 $9.3 billion and $8.8 billion at September 30, 2017, and December 31, 2016, respectively. The book value of our consolidated long-term debt, including current maturities, was $8.5 billion and $8.3 billion at September 30, 2017, and December 31, 2016, respectively. The estimated fair value of the aggregate of our and ONEOK Partners’ senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities. The estimated fair value of our consolidated long-term debt is classified as Level 2.

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D. RISK-MANAGEMENT AND HEDGING ACTIVITIES USING DERIVATIVES

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

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

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

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

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

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

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines retain natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which may expose this segment to commodity price risk depending on the regulatory treatment for this activity. To the extent that commodity price risk in our Natural Gas Pipelines segment is not mitigated by fuel cost-recovery mechanisms, we may use physical-forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At September 30, 2017, and December 31, 2016, there were no financial derivative instruments with respect to our natural gas pipeline operations.

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

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At September 30, 2017, and December 31, 2016, we had forward-starting interest-rate swaps with notional amounts totaling $1.3 billion and $1.2 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances and interest-rate swaps with notional amounts totaling $500 million and $1 billion, respectively, to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges.

Accounting Treatment - Our accounting treatment of derivative instruments is consistent with that disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report.

Fair Values of Derivative Instruments - See Note C for a discussion of the inputs associated with our fair value measurements. The following table sets forth the fair values of derivative instruments for the periods indicated:

		September 30, 2017		December 31, 2016	
	Location in our Consolidated Balance Sheets	Assets	(Liabilities)	Assets	(Liabilities)
		(Thousands of dollars)			
Derivatives designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	$9,180	$ (33,500)	$1,155	$ (49,938)
	Other assets/other deferred credits	2,098	(2,815)	210	(2,142)
Physical contracts	Other current liabilities	—	(3,600)	—	(3,022)
	Other deferred credits	—	(483)	—	—
Interest-rate contracts	Other current assets/other current liabilities	252	—	—	(12,795)
	Other assets	45,432	—	47,457	—
Total derivatives designated as hedging instruments		56,962	(40,398)	48,822	(67,897)
Derivatives not designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	5,862	(6,444)	4,346	(4,239)
	Other assets/other deferred credits	726	(708)	—	—
Total derivatives not designated as hedging instruments		6,588	(7,152)	4,346	(4,239)
Total derivatives		$63,550	$ (47,550)	$53,168	$ (72,136)

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

		September 30, 2017		December 31, 2016	
	Contract Type	Purchased/ Payor	Sold/ Receiver	Purchased/ Payor	Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
- Natural gas (Bcf)	Futures and swaps	—	(27.6)	—	(38.4)
- Natural gas (Bcf)	Put options	9.0	—	49.5	—
- Crude oil and NGLs (MMBbl)	Futures, forwards and swaps	2.8	(10.3)	—	(3.6)
Basis					
- Natural gas (Bcf)	Futures and swaps	—	(27.6)	—	(38.4)
Interest-rate contracts (Millions of dollars)	Swaps	$ 1,750.0	$ —	$ 2,150.0	$ —
Derivatives not designated as hedging instruments:					
Fixed price					
-Natural gas (Bcf)	Futures and swaps	2.7	—	0.4	—
- NGLs (MMBbl)	Futures, forwards and swaps	1.2	(2.2)	0.5	(0.7)
Basis					
- Natural gas (Bcf)	Futures and swaps	2.7	—	0.4	—

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

Cash Flow Hedges - At September 30, 2017, our Consolidated Balance Sheet reflected a net loss of $181.8 million in accumulated other comprehensive loss. The portion of accumulated other comprehensive loss attributable to our commodity derivative financial instruments is an unrealized loss of $19.9 million, net of tax, which is expected to be realized within the next three years as the forecasted transactions affect earnings. If commodity prices remain at current levels, we will realize approximately $19.1 million in net losses, net of tax, over the next 12 months and approximately $0.8 million in net losses, net of tax, thereafter. The amount deferred in accumulated other comprehensive loss attributable to our settled interest-rate swaps is a loss of $91.0 million, net of tax, which will be recognized over the life of the long-term, fixed-rate debt, including losses of $13.8 million, net of tax, that will be reclassified into earnings during the next 12 months as the hedged items affect earnings. The remaining amounts in accumulated other comprehensive loss are attributable primarily to forward-starting interest-rate swaps with future settlement dates, which are expected to be amortized to interest expense over the life of long-term, fixed-rate debt upon issuance of the debt.

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

	Three Months Ended		Nine Months Ended	
Derivatives in Cash Flow Hedging Relationships	September 30, 2017	2016	September 30, 2017	2016
	(Thousands of dollars)			

Commodity contracts	$(42,450)	$7,580	$(6,123)	$(39,396)
Interest-rate contracts	9,613	958	(3,853)	(59,217)
Total unrealized gain (loss) recognized in other comprehensive income (loss) on derivatives (effective portion)	$(32,837)	$8,538	$(9,976)	$(98,613)

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

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Effective Portion)	Three Months Ended September 30,		Nine Months Ended September 30,	
		2017	2016	2017	2016
		(Thousands of dollars)			
Commodity contracts	Commodity sales revenues	$(15,913)	$908	$(38,028)	$29,456
Interest-rate contracts	Interest expense	(4,820)	(4,802)	(15,321)	(14,302)
Total gain (loss) reclassified from accumulated other comprehensive loss into net income on derivatives (effective portion)		$(20,733)	$(3,894)	$(53,349)	$15,154

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

From time to time, we may enter into financial derivative instruments that contain provisions that require us to maintain an investment-grade credit rating from S&P and/or Moody's. If our credit ratings on our senior unsecured long-term debt were to decline below investment grade, the counterparties to the derivative instruments could request collateralization on derivative instruments in net liability positions. There were no financial derivative instruments with contingent features related to credit risk at September 30, 2017.

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

At September 30, 2017, the net credit exposure from our derivative assets is with investment-grade companies in the financial services sector.

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E. DEBT

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

	September 30, 2017	December 31, 2016
	(Thousands of dollars)	
ONEOK		
Senior unsecured obligations:		
Commercial paper outstanding, bearing a weighted-average interest rate of 1.93% (a)	$932,250	$—
$700,000 at 4.25% due February 2022	547,397	547,397
$500,000 at 7.5% due September 2023	500,000	500,000
$500,000 at 4.0% due July 2027	500,000	—
$100,000 at 6.5% due September 2028	—	87,126
$100,000 at 6.875% due September 2028	100,000	100,000
$400,000 at 6.0% due June 2035	400,000	400,000
$700,000 at 4.95% due July 2047	700,000	—
ONEOK Partners		
Commercial paper outstanding (a)	—	1,110,277
Senior unsecured obligations:		
$400,000 at 2.0% due October 2017	—	400,000
$425,000 at 3.2% due September 2018	425,000	425,000
$1,000,000 term loan, variable rate, due January 2019	500,000	1,000,000
$500,000 at 8.625% due March 2019	500,000	500,000
$300,000 at 3.8% due March 2020	300,000	300,000
$900,000 at 3.375 % due October 2022	900,000	900,000
$425,000 at 5.0 % due September 2023	425,000	425,000
$500,000 at 4.9 % due March 2025	500,000	500,000
$600,000 at 6.65% due October 2036	600,000	600,000
$600,000 at 6.85% due October 2037	600,000	600,000
$650,000 at 6.125% due February 2041	650,000	650,000
$400,000 at 6.2% due September 2043	400,000	400,000
Guardian Pipeline		
Weighted average 7.85% due December 2022	38,520	44,257
Total debt	9,518,167	9,489,057
Unamortized portion of terminated swaps	18,897	20,186
Unamortized debt issuance costs and discounts	(80,164)	(68,320)
Current maturities of long-term debt	(432,650)	(410,650)
Short-term borrowings (b)	(932,250)	(1,110,277)
Long-term debt	$8,092,000	$7,919,996

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

(b) - Individual issuances of commercial paper under our commercial paper program generally mature in 90 days or less. These issuances are supported by and reduce the borrowing capacity under the 2017 Credit Agreement.

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

The 2017 Credit Agreement includes a $100 million sublimit for the issuance of standby letters of credit and a $200 million sublimit for swingline loans. Under the terms of the 2017 Credit Agreement, we may request an increase in the size of the facility to an aggregate of $3.5 billion by either commitments from new lenders or increased commitments from existing lenders. The 2017 Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit ratings. Based on our current credit ratings, borrowings, if any, will accrue at LIBOR plus 110 basis points, and the annual facility fee is 15 basis points. We have the option to request two one-year extensions, subject to lender approval, which may be used for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes. At September 30, 2017, our ratio of indebtedness to adjusted EBITDA was 4.9 to 1, and we were in compliance with all covenants under the 2017 Credit Agreement.

Issuances - In July 2017, we completed an underwritten public offering of $1.2 billion senior unsecured notes consisting of $500 million, 4.0 percent senior notes due 2027, and $700 million, 4.95 percent senior notes due 2047. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were approximately $1.18 billion. The proceeds were used for general corporate purposes, which included repayment of existing indebtedness and capital expenditures.

In January 2016, ONEOK Partners entered into the $1.0 billion senior unsecured Term Loan Agreement with a syndicate of banks. The Term Loan Agreement matures in January 2019 and bears interest at LIBOR plus 130 basis points based on our current credit ratings. At September 30, 2017, the interest rate was 2.54 percent. The Term Loan 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. The Term Loan Agreement allows prepayment of all or any portion outstanding without penalty or premium and contains substantially the same covenants as our 2017 Credit Agreement. During the first quarter 2016, ONEOK Partners drew the full $1.0 billion available under the agreement and used the proceeds to repay $650 million of senior notes at maturity, to repay amounts outstanding under its commercial paper program and for general partnership purposes. In April 2017, ONEOK Partners entered into the first amendment to the Term Loan Agreement, which, among other things, added ONEOK as a guarantor to the Term Loan Agreement effective June 30, 2017, with the close of the Merger Transaction described in Note B.

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

In July 2017, we redeemed our 6.5 percent senior notes due 2028 at a redemption price of approximately $87 million, including the outstanding principal amount, plus accrued and unpaid interest, with cash on hand.

Also in July 2017, we repaid $500 million of the $1.0 billion Term Loan Agreement due 2019.

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

F. EQUITY

Ownership Interest in ONEOK Partners - At December 31, 2016, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners consisting of approximately 41.3 million common units and 73.0 million Class B units, which are convertible, at our option, into common units. The portion of ONEOK Partners that we did not own is reflected in our 2016 Consolidated Balance Sheet under the caption

“Noncontrolling interests” along with the 20 percent of WTLPG that we do not own. On June 30, 2017, we completed the Merger Transaction at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit that we did not already own. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. At September 30, 2017, the caption “Noncontrolling interests” on our Consolidated Balance Sheet reflects only the 20 percent of WTLPG that we do not own.

Cash Distributions - Prior to the consummation of the Merger Transaction, we received distributions from ONEOK Partners on our common and Class B units and our 2 percent general partner interest, which included our incentive distribution rights. Additional information about ONEOK Partners’ cash distributions and our incentive distribution rights for the periods prior to June 30, 2017, is included under “Cash Distributions” in Note O of the Notes to Consolidated Financial Statements in our Annual Report.

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Distributions paid to ONEOK Partners unitholders of record at the close of business on January 30, 2017, and May 1, 2017, were $0.79 per unit. As a result of the Merger Transaction, we are entitled to receive all available ONEOK Partners cash. Our incentive distribution rights effectively terminated at the close of the Merger Transaction.

The following table sets forth ONEOK Partners' distributions declared and paid during the periods prior to the closing of the Merger Transaction on June 30, 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Thousands, except per unit amounts)			
Distribution per unit	$ —	$ 0.79	$ 1.58	$ 2.37
General partner distributions	$ —	$ 6,660	$ 13,320	$ 19,980
Incentive distributions	—	100,538	201,076	301,614
Distributions to general partner	—	107,198	214,396	321,594
Limited partner distributions to ONEOK	—	90,323	180,646	270,969
Limited partner distributions to other unitholders	—	135,480	270,959	406,439
Total distributions paid	$ —	$ 333,001	$ 666,001	$ 999,002

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 on our common stock to shareholders of record at the close of business on January 30, 2017, May 1, 2017, and August 7, 2017, were $0.615, $0.615, and $0.745 per share, respectively. A dividend of $0.745 per share was declared for shareholders of record at the close of business on November 6, 2017, payable November 14, 2017.

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 the second quarter 2017 and is included in other expense in our Consolidated Statements of Income. The Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. In August 2017, we paid dividends of $0.4 million for the Series E Preferred Stock. Dividends totaling approximately $0.3 million were declared for the Series E Preferred Stock and are payable November 14, 2017. The $20 million issuance of the shares of Series E Preferred Stock and the related accrued dividends of approximately $0.1 million at September 30, 2017, represent noncash financing activities.

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

During the three months ended September 30, 2017, we sold 1.2 million shares of common stock through our "at-the-market" equity program that resulted in net proceeds of $64.7 million, of which $30.8 million had settled as of September 30, 2017. In October 2017, we sold an additional 2.1 million shares of common stock through this program that resulted in net proceeds of $119.5 million. The net proceeds from these issuances were used for general corporate purposes, including repayment of outstanding indebtedness and to fund capital expenditures.

Prior to the close of the Merger Transaction, ONEOK Partners had an “at-the-market” equity program for the offer and sale from time to time of its common units, up to an aggregate amount of $650 million. During the six months ended June 30, 2017, and the year ended December 31, 2016, no common units were sold through ONEOK Partners’ “at-the-market” equity program. Upon the close of the Merger Transaction on June 30, 2017, the ONEOK Partners “at-the-market” equity program terminated.

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G. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities (a)	Pension and Postretirement Benefit Plan Obligations (a) (b)	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities of Unconsolidated Affiliates (a)	Accumulated Other Comprehensive Loss (a)
	(Thousands of dollars)			
January 1, 2017	$(52,155)	$ (101,236)	$ (959)	$ (154,350)
Other comprehensive income (loss) before reclassifications	(14,892)	8	(588)	(15,472)
Amounts reclassified from accumulated other comprehensive loss	22,126	6,114	99	28,339
Impact of Merger Transaction (Note B) (c)	(40,288)	—	—	(40,288)
Net current-period other comprehensive income (loss) attributable to ONEOK	(33,054)	6,122	(489)	(27,421)
September 30, 2017	$(85,209)	$ (95,114)	$ (1,448)	$ (181,771)

(a) - All amounts are presented net of tax.

(b) - Includes amounts related to supplemental executive retirement plan.

(c) - Includes the remaining portion of ONEOK Partners’ accumulated other comprehensive loss at June 30, 2017, that we acquired in the Merger Transaction, related to commodity and interest-rate contracts.

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The following table sets forth the effect of reclassifications from accumulated other comprehensive loss in our Consolidated Statements of Income for the periods indicated:

Details about Accumulated Other Comprehensive Loss Components	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016	Affected Line Item in the Consolidated Statements of Income
	(Thousands of dollars)				
Unrealized gains (losses) on risk-management assets/liabilities					
Commodity contracts	$(15,913)	$908	$(38,028)	$29,456	Commodity sales revenues
Interest-rate contracts	(4,820)	(4,802)	(15,321)	(14,302)	Interest expense
	(20,733)	(3,894)	(53,349)	15,154	Income before income taxes
	7,671	811	13,077	(1,658)	Income tax expense
	(13,062)	(3,083)	(40,272)	13,496	Net income
Noncontrolling interests	—	(1,774)	(18,146)	10,459	Less: Net income attributable to noncontrolling interests
	$(13,062)	$(1,309)	$(22,126)	$3,037	Net income attributable to ONEOK
Pension and postretirement benefit plan obligations (a)					
Amortization of net loss	$(3,811)	$(2,999)	$(11,435)	$(8,994)	
Amortization of unrecognized prior service cost	415	416	1,245	1,246	
	(3,396)	(2,583)	(10,190)	(7,748)	Income before income taxes
	1,358	1,033	4,076	3,099	Income tax expense
	$(2,038)	$(1,550)	$(6,114)	$(4,649)	Net income attributable to ONEOK
Unrealized gains (losses) on risk-management assets/liabilities of unconsolidated affiliates					
	$(83)	$—	$(264)	$—	Equity in net earnings from investments
	31	—	59	—	Income tax expense
	(52)	—	(205)	—	Net income
Noncontrolling interests	—	—	(106)	—	Less: Net income attributable to noncontrolling interests
	$(52)	$—	$(99)	$—	Net income attributable to ONEOK
Total reclassifications for the period attributable to ONEOK	$(15,152)	$(2,859)	$(28,339)	$(1,612)	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 I for additional detail of our net periodic benefit cost.

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H. EARNINGS PER SHARE

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

	Three Months Ended September 30, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$165,466	380,907	$ 0.43
Diluted EPS from continuing operations			
Effect of dilutive securities	—	2,512	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$165,466	383,419	$ 0.43

	Three Months Ended September 30, 2016		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$92,720	211,309	$ 0.44
Diluted EPS from continuing operations			
Effect of dilutive securities	—	1,561	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$92,720	212,870	$ 0.44

	Nine Months Ended September 30, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$324,303	268,108	$ 1.21
Diluted EPS from continuing operations			
Effect of dilutive securities	—	2,241	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$324,303	270,349	$ 1.20

	Nine Months Ended September 30, 2016		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations attributable to ONEOK available for common stock	$263,289	211,038	$ 1.25
Diluted EPS from continuing operations			
Effect of dilutive securities	—	1,085	
Income from continuing operations attributable to ONEOK available for common stock and common stock equivalents	$263,289	212,123	$ 1.24

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I. EMPLOYEE BENEFIT PLANS

The following tables set forth the components of net periodic benefit cost for our pension and postretirement benefit plans for our continuing operations for the periods indicated:

	Pension Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Components of net periodic benefit cost				
Service cost	$1,721	$1,622	$5,165	$4,866
Interest cost	4,655	4,946	13,965	14,840
Expected return on plan assets	(5,336)	(5,077)	(16,008)	(15,231)
Amortization of net loss	3,392	2,737	10,176	8,210
Net periodic benefit cost	$4,432	$4,228	$13,298	$12,685

	Postretirement Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Components of net periodic benefit cost				
Service cost	$165	$149	$495	$447
Interest cost	565	601	1,695	1,803
Expected return on plan assets	(564)	(531)	(1,692)	(1,593)
Amortization of prior service credit	(415)	(416)	(1,245)	(1,246)
Amortization of net loss	419	262	1,259	784
Net periodic benefit cost	$170	$65	$512	$195

J. UNCONSOLIDATED AFFILIATES

Equity in Net Earnings from Investments - The following table sets forth our equity in net earnings from investments for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Northern Border Pipeline	$16,440	$17,854	$50,879	$52,251
Overland Pass Pipeline Company	15,793	13,886	44,243	40,798
Other	7,825	3,415	23,863	7,392
Equity in net earnings from investments	$40,058	$35,155	$118,985	$100,441
Impairment of equity investments	$(4,270)	$—	$(4,270)	$—

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
	(Thousands of dollars)			
Income Statement				
Operating revenues	$163,627	$143,967	$475,510	$423,170
Operating expenses	$69,740	$66,490	$206,141	$191,863
Net income	$87,330	$72,672	$260,533	$214,129
Distributions paid to us	$49,414	$40,822	$146,094	$149,399

We incurred expenses in transactions with unconsolidated affiliates of $39.9 million and $36.4 million for the three months ended September 30, 2017 and 2016, respectively, and $116.0 million and $105.3 million for the nine months ended September 30, 2017 and 2016, respectively, primarily related to Overland Pass Pipeline Company and Northern Border Pipeline. Accounts payable to our equity-method investees at September 30, 2017, and December 31, 2016, were $13.1 million and $11.1 million, respectively.

Northern Border Pipeline - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline’s partners are to be made on a pro rata basis according to each partner’s percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline’s financial statements based upon EBITDA less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. During the nine months ended September 30, 2017, we made an equity contribution of $83 million to Northern Border Pipeline.

Overland Pass Pipeline Company - The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company’s members are to be made on a pro rata basis according to each member’s percentage interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Company Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

Roadrunner Gas Transmission - The Roadrunner limited liability company agreement provides that distributions to members are made on a pro rata basis according to each member’s ownership interest. As the operator, we have been delegated the authority to determine such distributions in accordance with, and on the frequency set forth in, the Roadrunner limited liability company agreement. Cash distributions are equal to 100 percent of available cash, as defined in the limited liability company agreement.

We have an operating agreement with Roadrunner that provides for reimbursement or payment to us for management services and certain operating costs. Reimbursements and payments from Roadrunner included in operating income in our Consolidated Statements of Income for the three and nine months ended September 30, 2017 and 2016, were not material.

K. COMMITMENTS AND CONTINGENCIES

Environmental Matters and Pipeline Safety - The operation of pipelines, plants and other facilities for the gathering, processing, transportation and storage of natural gas, NGLs, condensate and other products is subject to numerous and complex laws and regulations pertaining to health, safety and the environment. As an owner and/or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental 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. Management

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believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Legal Proceedings - Gas Index Pricing Litigation - As was previously reported, the United States District Court for the District of Nevada (the Court) granted summary judgment in March 2017 to our affiliate ONEOK Energy Services Company, L.P. (OESC) in Sinclair Oil Corporation v. ONEOK Energy Services Company, L.P. (filed in the United States District Court for the District of Wyoming in September 2005, transferred to MDL-1566 in the Court) after determining that the plaintiff's claim was barred by a release obtained in a prior lawsuit against us and OESC. In September 2017, the Court entered a final judgment in favor of OESC in Sinclair. Later that month, Sinclair Oil Corporation filed a notice of appeal of this decision to the Ninth Circuit Court of Appeals. We expect that future charges, if any, from the ultimate resolution of the Sinclair case will not be material to our results of operations, financial position or cash flows.

As was previously reported, the Court gave final approval in May 2017 to the previously announced settlements of Learjet, Inc., et al. v. ONEOK, Inc., et al. (filed in the District Court of Wyandotte, Kansas, in November 2005, transferred to MDL-1566 in the Court); Arandell Corporation, et al. v. Xcel Energy, Inc., et al. (filed in the Circuit Court for Dane County, Wisconsin, in December 2006, transferred to MDL-1566 in the Court); Heartland Regional Medical Center, et al. v. ONEOK, Inc., et al. (filed in the Circuit Court of Buchanan County, Missouri, in March 2007, transferred to MDL-1566 in the Court); and NewPage Wisconsin System v. CMS Energy Resource Management Company, et al. (filed in the Circuit Court for Wood County, Wisconsin, in March 2009, transferred to MDL-1566 in the Court and now consolidated with the Arandell case). Thereafter, the Court entered a final judgment dismissing these actions with prejudice as to us and our affiliates, which became final and nonappealable in July 2017. The amount paid to settle these cases was not material to our results of operations, financial position or cash flows and was paid with cash on hand.

ONEOK Partners Class Action Litigation - As was previously reported, ONEOK Partners settled two putative class action lawsuits captioned Juergen Krueger, Individually And On Behalf Of All Others Similarly Situated v. ONEOK Partners, L.P., et al. (filed in the United States District Court for the Northern District of Oklahoma) and Max Federman, On Behalf of Himself and All Others Similarly Situated v. ONEOK Partners, L.P., et al. (filed in the United States District Court for the Northern District of Oklahoma) by agreeing to make certain disclosures in a filing with the SEC about the Merger Transaction in addition to those made in the final proxy statement filed with the SEC. The Krueger and Federman actions were dismissed on June 14, 2017, as moot, with prejudice as to the named plaintiffs and without prejudice as to any other members of a putative class. In July 2017, ONEOK Partners entered into a settlement concerning attorney's fees and expenses for plaintiffs' counsel that was not material to our results of operations, financial position or cash flows and was paid with cash on hand.

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

L. 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 and Merger Transaction-related costs, the operating and leasing activities of our headquarters building and related parking facility and eliminations necessary to reconcile our reportable segments to our Consolidated Financial Statements.

Accounting Policies - The accounting policies of the segments are described in Note A of the Notes to Consolidated Financial Statements in our Annual Report. 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

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EBITDA for each segment is defined as net income adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, allowance for equity funds used during construction, noncash compensation and other noncash items. This calculation may not be comparable with similarly titled measures of other companies.

Customers - The primary customers of our Natural Gas Gathering and Processing segment are crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. Our Natural Gas Pipelines segment's customers are primarily local natural gas distribution companies, electric-generation companies, large industrial companies, municipalities, irrigation customers and marketing companies.

For the three and nine months ended September 30, 2017 and 2016, we had no single customer from which we received 10 percent or more of our consolidated revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Three Months Ended September 30, 2017	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
Sales to unaffiliated customers	$453,432	$2,348,052	$104,340	$2,905,824
Intersegment revenues	329,496	153,927	2,098	485,521
Total revenues	782,928	2,501,979	106,438	3,391,345
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(566,988)	(2,136,207)	(10,614)	(2,713,809)
Operating costs	(80,197)	(90,234)	(29,838)	(200,269)
Equity in net earnings from investments	3,433	15,287	21,338	40,058
Other	2,774	3,094	203	6,071
Segment adjusted EBITDA	$141,950	$293,919	$87,527	$523,396
Depreciation and amortization	$(46,842)	$(41,929)	$(12,765)	$(101,536)
Impairment of long-lived assets and equity investments	$(20,240)	$—	$—	$(20,240)
Capital expenditures	$85,542	$27,024	$18,811	$131,377

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $293.1 million, of which $250.2 million related to sales within the segment and cost of sales and fuel of $124.2 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $65.6 million and cost of sales and fuel of $10.5 million.

Three Months Ended September 30, 2017	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$2,905,824	$542	$2,906,366
Intersegment revenues	485,521	(485,521)	—

Total revenues	$3,391,345	$(484,979)	$2,906,366
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(2,713,809)	$484,393	$(2,229,416)
Operating costs	$(200,269)	$(6,781)	$(207,050)
Depreciation and amortization	$(101,536)	$(762)	$(102,298)
Impairment of long-lived assets and equity investments	$(20,240)	$—	$(20,240)
Equity in net earnings from investments	$40,058	$—	$40,058
Capital expenditures	$131,377	$3,822	$135,199

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Three Months Ended September 30, 2016	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
Sales to unaffiliated customers	$361,717	$1,905,273	$90,401	$2,357,391
Intersegment revenues	150,501	133,984	1,676	286,161
Total revenues	512,218	2,039,257	92,077	2,643,552
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(336,456)	(1,694,161)	(6,870)	(2,037,487)
Operating costs	(69,443)	(79,771)	(28,373)	(177,587)
Equity in net earnings from investments	2,596	13,960	18,599	35,155
Other	922	(29)	4,871	5,764
Segment adjusted EBITDA	$109,837	$279,256	$80,304	$469,397
Depreciation and amortization	$(44,994)	$(40,751)	$(12,057)	$(97,802)
Capital expenditures	$99,649	$30,533	$24,495	$154,677

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $299.2 million, of which $253.4 million related to sales within the segment and cost of sales and fuel of $119.6 million.

(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $61.0 million and cost of sales and fuel of $7.8 million.

Three Months Ended September 30, 2016	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$2,357,391	$516	$2,357,907
Intersegment revenues	286,161	(286,161)	—
Total revenues	$2,643,552	$(285,645)	$2,357,907
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(2,037,487)	$285,894	$(1,751,593)
Operating costs	$(177,587)	$(6,564)	$(184,151)
Depreciation and amortization	$(97,802)	$(748)	$(98,550)
Equity in net earnings from investments	$35,155	$—	$35,155
Capital expenditures	$154,677	$3,597	$158,274

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Nine Months Ended September 30, 2017	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
Sales to unaffiliated customers	$1,286,669	$6,788,451	$305,019	$8,380,139
Intersegment revenues	843,350	455,197	6,086	1,304,633
Total revenues	2,130,019	7,243,648	311,105	9,684,772
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(1,544,263)	(6,188,501)	(33,990)	(7,766,754)
Operating costs	(225,079)	(256,262)	(92,468)	(573,809)
Equity in net earnings from investments	9,843	44,071	65,071	118,985
Other	3,658	2,501	1,427	7,586
Segment adjusted EBITDA	$374,178	$845,457	$251,145	$1,470,780
Depreciation and amortization	$(137,843)	$(124,471)	$(37,906)	$(300,220)
Impairment of long-lived assets and equity investments	$(20,240)	$—	$—	$(20,240)
Total assets	$5,385,778	$8,515,535	$2,040,445	$15,941,758
Capital expenditures	$185,713	$59,813	$70,671	$316,197

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $878.8 million, of which $752.5 million related to sales within the segment and cost of sales and fuel of $359.6 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $197.3 million and cost of sales and fuel of $32.9 million.

Nine Months Ended September 30, 2017	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$8,380,139	$1,610	$8,381,749
Intersegment revenues	1,304,633	(1,304,633)	—
Total revenues	$9,684,772	$(1,303,023)	$8,381,749
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(7,766,754)	$1,302,473	$(6,464,281)
Operating costs	$(573,809)	$(42,968)	$(616,777)
Depreciation and amortization	$(300,220)	$(2,346)	$(302,566)
Impairment of long-lived assets and equity investments	$(20,240)	$—	$(20,240)
Equity in net earnings from investments	$118,985	$—	$118,985
Total assets	$15,941,758	$823,083	$16,764,841
Capital expenditures	$316,197	$14,234	$330,431

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Nine Months Ended September 30, 2016	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
Sales to unaffiliated customers	$971,834	$5,030,820	$262,276	$6,264,930
Intersegment revenues	449,154	367,820	3,843	820,817
Total revenues	1,420,988	5,398,640	266,119	7,085,747
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(902,747)	(4,376,345)	(15,914)	(5,295,006)
Operating costs	(208,353)	(236,722)	(85,075)	(530,150)
Equity in net earnings from investments	7,987	41,211	51,243	100,441
Other	2,295	(748)	6,812	8,359
Segment adjusted EBITDA	$320,170	$826,036	$223,185	$1,369,391
Depreciation and amortization	$(133,258)	$(122,153)	$(34,634)	$(290,045)
Total assets	$5,268,161	$8,257,203	$1,912,951	$15,438,315
Capital expenditures	$325,820	$85,519	$71,721	$483,060

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $878.5 million, of which $742.6 million related to sales within the segment and cost of sales and fuel of $339.1 million.

(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $172.4 million and cost of sales and fuel of $19.1 million.

Nine Months Ended September 30, 2016	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$6,264,930	$1,543	$6,266,473
Intersegment revenues	820,817	(820,817)	—
Total revenues	$7,085,747	$(819,274)	$6,266,473
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(5,295,006)	$820,352	$(4,474,654)
Operating costs	$(530,150)	$(22,855)	$(553,005)
Depreciation and amortization	$(290,045)	$(2,230)	$(292,275)
Equity in net earnings from investments	$100,441	$—	$100,441
Total assets	$15,438,315	$543,720	$15,982,035
Capital expenditures	$483,060	$8,468	$491,528

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Reconciliation of income from continuing operations to total segment adjusted EBITDA	(Thousands of dollars)			
Income from continuing operations	$166,531	$194,792	$528,707	$550,789
Add:				
Interest expense, net of capitalized interest	126,533	118,240	361,468	355,463
Depreciation and amortization	102,298	98,550	302,566	292,275
Income taxes	97,128	55,012	195,913	157,536

Impairment charges	20,240	—	20,240	—
Noncash compensation expense	4,883	3,165	9,790	20,170
Other corporate costs and noncash items (a)	5,783	(362)	52,096	(6,842)
Total segment adjusted EBITDA	$523,396	$469,397	$1,470,780	$1,369,391

(a) - The nine months ended September 30, 2017, includes our April 2017 $20 million contribution of Series E Preferred Stock to the Foundation and costs related to the Merger Transaction of $29.5 million.

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M. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

ONEOK and ONEOK Partners are issuers of certain public debt securities. Effective with the Merger Transaction, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners. The Intermediate Partnership holds all of ONEOK Partners' partnership interests and equity in its subsidiaries, as well as a 50 percent interest in Northern Border Pipeline. In lieu of providing separate financial statements for each subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuers in separate columns in this single set of condensed consolidating financial statements.

For purposes of the following footnote:

- we are referred to as "Parent Issuer and Guarantor";
- ONEOK Partners is referred to as "Subsidiary Issuer and Guarantor";
- the Intermediate Partnership is referred to as "Guarantor Subsidiary"; and
- the "Non-Guarantor Subsidiaries" are all subsidiaries other than the Guarantor Subsidiary and Subsidiary Issuer and Guarantor.

The following unaudited 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.

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Condensed Consolidating Statements of Income

(Unaudited)	Three Months Ended September 30, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$ —	$ —	$ 2,322.5	$ —	$2,322.5
Services	—	—	—	584.3	(0.5)	583.8
Total revenues	—	—	—	2,906.8	(0.5)	2,906.3
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	2,229.4	—	2,229.4
Operating expenses	3.9	—	2.6	303.3	(0.5)	309.3
Impairment of long-lived assets	—	—	—	16.0	—	16.0
Gain on sale of assets	—	—	—	(0.3)	—	(0.3)
Operating income	(3.9)	—	(2.6)	358.4	—	351.9
Equity in net earnings from investments	298.0	298.3	300.9	27.6	(884.7)	40.1
Impairment of equity investments	—	—	—	(4.3)	—	(4.3)
Other income (expense), net	6.8	86.1	86.1	(4.3)	(172.2)	2.5
Interest expense, net	(43.2)	(86.1)	(86.1)	(83.3)	172.2	(126.5)
Income before income taxes	257.7	298.3	298.3	294.1	(884.7)	263.7
Income taxes	(91.9)	—	—	(5.3)	—	(97.2)
Net income	165.8	298.3	298.3	288.8	(884.7)	166.5
Less: Net income attributable to noncontrolling interests	0.1	—	—	0.7	—	0.8
Net income attributable to ONEOK	165.7	298.3	298.3	288.1	(884.7)	165.7
Less: Preferred stock dividends	0.2	—	—	—	—	0.2
Net income available to common shareholders	$165.5	$ 298.3	$ 298.3	$ 288.1	$ (884.7)	$165.5

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(Unaudited)	Three Months Ended September 30, 2016 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$ —	$ —	$ 1,840.5	$ —	$1,840.5
Services	—	—	—	517.9	(0.5)	517.4
Total revenues	—	—	—	2,358.4	(0.5)	2,357.9
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	1,751.6	—	1,751.6
Operating expenses	6.7	—	—	276.4	(0.5)	282.6
Gain on sale of assets	—	—	—	(5.7)	—	(5.7)
Operating income	(6.7)	—	—	336.1	—	329.4
Equity in net earnings from investments	273.5	274.3	274.3	17.4	(804.3)	35.2
Other income (expense), net	3.4	95.3	95.3	—	(190.6)	3.4
Interest expense, net	(25.7)	(95.3)	(95.3)	(92.5)	190.6	(118.2)
Income before income taxes	244.5	274.3	274.3	261.0	(804.3)	249.8
Income taxes	(51.4)	—	—	(3.6)	—	(55.0)
Income from continuing operations	193.1	274.3	274.3	257.4	(804.3)	194.8
Income (loss) from discontinued operations, net of tax	—	—	—	(0.6)	—	(0.6)
Net income	193.1	274.3	274.3	256.8	(804.3)	194.2
Less: Net income attributable to noncontrolling interests	101.0	—	—	1.1	—	102.1
Net income attributable to ONEOK	$92.1	$ 274.3	$ 274.3	$ 255.7	$ (804.3)	$92.1

(Unaudited)	Nine Months Ended September 30, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$ —	$ —	$ 6,700.3	$ —	$6,700.3
Services	—	—	—	1,683.0	(1.5)	1,681.5
Total revenues	—	—	—	8,383.3	(1.5)	8,381.8
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	6,464.3	—	6,464.3
Operating expenses	34.0	—	8.8	878.0	(1.5)	919.3
Impairment of long-lived assets	—	—	—	16.0	—	16.0
Gain on sale of assets	—	—	—	(0.9)	—	(0.9)
Operating income	(34.0)	—	(8.8)	1,025.9	—	983.1
Equity in net earnings from investments	842.0	845.9	854.7	72.1	(2,495.7)	119.0
Impairment of equity investments	—	—	—	(4.3)	—	(4.3)
Other income (expense), net	(7.4)	272.2	272.2	(4.3)	(544.4)	(11.7)
Interest expense, net	(93.5)	(272.2)	(272.2)	(268.0)	544.4	(361.5)
Income before income taxes	707.1	845.9	845.9	821.4	(2,495.7)	724.6

Income taxes	(180.9)	—	—	(15.0)	—	(195.9)
Net income	526.2	845.9	845.9	806.4	(2,495.7)	528.7
Less: Net income attributable to noncontrolling interests	201.4	—	—	2.5	—	203.9
Net income attributable to ONEOK	324.8	845.9	845.9	803.9	(2,495.7)	324.8
Less: Preferred stock dividends	0.5	—	—	—	—	0.5
Net income available to common shareholders	$324.3	$ 845.9	$ 845.9	$ 803.9	$ (2,495.7)	$324.3

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(Unaudited)	Nine Months Ended September 30, 2016 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$ —	$ —	$ 4,757.3	$ —	$4,757.3
Services	—	—	—	1,510.7	(1.5)	1,509.2
Total revenues	—	—	—	6,268.0	(1.5)	6,266.5
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	4,474.7	—	4,474.7
Operating expenses	23.1	—	—	823.6	(1.5)	845.2
Gain on sale of assets	—	—	—	(9.5)	—	(9.5)
Operating income	(23.1)	—	—	979.2	—	956.1
Equity in net earnings from investments	786.8	789.3	789.3	48.2	(2,313.2)	100.4
Other income (expense), net	7.8	284.6	284.6	(0.5)	(569.2)	7.3
Interest expense, net	(77.1)	(284.6)	(284.6)	(278.4)	569.2	(355.5)
Income before income taxes	694.4	789.3	789.3	748.5	(2,313.2)	708.3
Income taxes	(149.8)	—	—	(7.7)	—	(157.5)
Income from continuing operations	544.6	789.3	789.3	740.8	(2,313.2)	550.8
Income (loss) from discontinued operations, net of tax	—	—	—	(1.8)	—	(1.8)
Net income	544.6	789.3	789.3	739.0	(2,313.2)	549.0
Less: Net income attributable to noncontrolling interests	283.1	—	—	4.4	—	287.5
Net income attributable to ONEOK	$261.5	$ 789.3	$ 789.3	$ 734.6	$ (2,313.2)	$261.5

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Condensed Consolidating Statements of Comprehensive Income

(Unaudited)	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	Three Months Ended September 30, 2017					
	(Millions of dollars)					
Net income	$165.8	$298.3	$298.3	$288.8	$(884.7)	$166.5
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	18.4	(61.9)	(42.4)	(19.5)	84.8	(20.6)
Realized (gains) losses on derivatives in net income, net of tax	0.6	19.8	15.9	8.6	(31.8)	13.1
Change in pension and postretirement benefit plan liability, net of tax	2.0	—	—	—	—	2.0
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(0.3)	(0.3)	(0.2)	0.6	(0.2)
Total other comprehensive income (loss)	21.0	(42.4)	(26.8)	(11.1)	53.6	(5.7)
Comprehensive income	186.8	255.9	271.5	277.7	(831.1)	160.8
Less: Comprehensive income attributable to noncontrolling interests	—	—	—	0.7	—	0.7
Comprehensive income attributable to ONEOK	$186.8	$255.9	$271.5	$277.0	$(831.1)	$160.1

(Unaudited)	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	Three Months Ended September 30, 2016					
	(Millions of dollars)					
Net income	$193.1	$274.3	$274.3	$256.8	$(804.3)	$194.2
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	—	8.5	7.6	14.8	(23.7)	7.2
Realized (gains) losses on derivatives in net income, net of tax	0.5	3.0	(1.0)	1.0	(0.4)	3.1
Change in pension and postretirement benefit plan liability, net of tax	1.6	—	—	—	—	1.6
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(0.7)	(0.7)	(1.3)	2.1	(0.6)
Total other comprehensive income (loss)	2.1	10.8	5.9	14.5	(22.0)	11.3
Comprehensive income	195.2	285.1	280.2	271.3	(826.3)	205.5
Less: Comprehensive income attributable to noncontrolling interests	107.4	—	—	1.1	—	108.5
Comprehensive income attributable to ONEOK	$87.8	$285.1	$280.2	$270.2	$(826.3)	$97.0

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(Unaudited)	Nine Months Ended September 30, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Net income	$526.2	$ 845.9	$ 845.9	$ 806.4	$ (2,495.7)	$528.7
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	18.1	(38.8)	(6.1)	13.3	12.2	(1.3)
Realized (gains) losses on derivatives in net income, net of tax	1.6	50.7	38.0	26.0	(76.0)	40.3
Change in pension and postretirement benefit plan liability, net of tax	6.1	—	—	—	—	6.1
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(1.5)	(1.5)	(1.2)	3.0	(1.2)
Total other comprehensive income (loss)	25.8	10.4	30.4	38.1	(60.8)	43.9
Comprehensive income	552.0	856.3	876.3	844.5	(2,556.5)	572.6
Less: Comprehensive income attributable to noncontrolling interests	232.4	—	—	2.5	—	234.9
Comprehensive income attributable to ONEOK	$319.6	$ 856.3	$ 876.3	$ 842.0	$ (2,556.5)	$337.7

(Unaudited)	Nine Months Ended September 30, 2016 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Net income	$544.6	$ 789.3	$ 789.3	$ 739.0	$ (2,313.2)	$549.0
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	—	(98.6)	(39.4)	(123.0)	177.4	(83.6)
Realized (gains) losses on derivatives in net income, net of tax	1.6	(17.8)	(29.5)	(43.0)	75.2	(13.5)
Change in pension and postretirement benefit plan liability, net of tax	4.7	—	—	—	—	4.7
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	(12.1)	(12.1)	(22.3)	36.3	(10.2)
Total other comprehensive income (loss)	6.3	(128.5)	(81.0)	(188.3)	288.9	(102.6)
Comprehensive income	550.9	660.8	708.3	550.7	(2,024.3)	446.4
Less: Comprehensive income attributable to noncontrolling interests	207.6	—	—	4.4	—	212.0
Comprehensive income attributable to ONEOK	$343.3	$ 660.8	$ 708.3	$ 546.3	$ (2,024.3)	$234.4

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Condensed Consolidating Balance Sheets

(Unaudited)	September 30, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	(Millions of dollars)					
Current assets						
Cash and cash equivalents	$11.7	$—	$—	$ —	$—	$11.7
Accounts receivable, net	—	—	—	939.6	—	939.6
Natural gas and natural gas liquids in storage	—	—	—	314.3	—	314.3
Other current assets	10.6	0.3	—	242.4	—	253.3
Total current assets	22.3	0.3	—	1,496.3	—	1,518.9
Property, plant and equipment						
Property, plant and equipment	139.8	—	—	15,224.5	—	15,364.3
Accumulated depreciation and amortization	96.2	—	—	2,689.5	—	2,785.7
Net property, plant and equipment	43.6	—	—	12,535.0	—	12,578.6
Investments and other assets						
Investments	5,684.0	3,099.4	7,711.6	809.1	(16,290.4)	1,013.7
Intercompany notes receivable	2,831.9	8,605.5	3,993.3	—	(15,430.7)	—
Other assets	707.4	0.2	—	1,015.9	(69.9)	1,653.6
Total investments and other assets	9,223.3	11,705.1	11,704.9	1,825.0	(31,791.0)	2,667.3
Total assets	$9,289.2	$11,705.4	$11,704.9	$ 15,856.3	$(31,791.0)	$16,764.8
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$—	$425.0	$—	$ 7.7	$—	$432.7
Short-term borrowings	932.3	—	—	—	—	932.3
Accounts payable	6.8	—	—	916.0	—	922.8
Other current liabilities	47.8	68.2	—	337.2	—	453.2
Total current liabilities	986.9	493.2	—	1,260.9	—	2,741.0
Intercompany debt	—	—	8,605.5	6,825.2	(15,430.7)	—
Long-term debt, excluding current maturities	2,726.1	5,335.2	—	30.7	—	8,092.0
Deferred credits and other liabilities	216.7	—	—	268.6	(69.9)	415.4
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	5,359.5	5,877.0	3,099.4	7,314.0	(16,290.4)	5,359.5
Noncontrolling interests in consolidated subsidiaries	—	—	—	156.9	—	156.9
Total equity	5,359.5	5,877.0	3,099.4	7,470.9	(16,290.4)	5,516.4
Total liabilities and equity	$9,289.2	$11,705.4	$11,704.9	$ 15,856.3	$(31,791.0)	$16,764.8

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(Unaudited)	December 31, 2016 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	(Millions of dollars)					
Current assets						
Cash and cash equivalents	$248.5	$—	$0.4	$ —	$—	$248.9
Accounts receivable, net	—	—	—	872.4	—	872.4
Natural gas and natural gas liquids in storage	—	—	—	140.0	—	140.0
Other current assets	7.2	—	—	160.6	—	167.8
Assets of discontinued operations	—	—	—	0.6	—	0.6
Total current assets	255.7	—	0.4	1,173.6	—	1,429.7
Property, plant and equipment						
Property, plant and equipment	139.8	—	—	14,938.7	—	15,078.5
Accumulated depreciation and amortization	90.4	—	—	2,416.7	—	2,507.1
Net property, plant and equipment	49.4	—	—	12,522.0	—	12,571.4
Investments and other assets						
Investments	2,931.9	3,222.1	6,805.4	631.1	(12,631.7)	958.8
Intercompany notes receivable	205.2	10,615.0	7,031.3	—	(17,851.5)	—
Other assets	103.4	47.5	—	1,028.0	—	1,178.9
Total investments and other assets	3,240.5	13,884.6	13,836.7	1,659.1	(30,483.2)	2,137.7
Total assets	$3,545.6	$13,884.6	$13,837.1	$ 15,354.7	$(30,483.2)	$16,138.8
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$3.0	$400.0	$—	$ 7.7	$—	$410.7
Short-term borrowings	—	1,110.3	—	—	—	1,110.3
Accounts payable	13.0	—	—	861.7	—	874.7
Other current liabilities	44.7	99.9	—	296.5	—	441.1
Total current liabilities	60.7	1,610.2	—	1,165.9	—	2,836.8
Intercompany debt	—	—	10,615.0	7,236.5	(17,851.5)	—
Long-term debt, excluding current maturities	1,628.7	6,254.7	—	36.6	—	7,920.0
Deferred credits and other liabilities	1,667.5	—	—	285.6	—	1,953.1
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	188.7	6,019.7	3,222.1	6,472.0	(15,713.8)	188.7
Noncontrolling interests in consolidated subsidiaries	—	—	—	158.1	3,082.1	3,240.2
Total equity	188.7	6,019.7	3,222.1	6,630.1	(12,631.7)	3,428.9
Total liabilities and equity	$3,545.6	$13,884.6	$13,837.1	$ 15,354.7	$(30,483.2)	$16,138.8

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Condensed Consolidating Statements of Cash Flows

(Unaudited)	Nine Months Ended September 30, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$620.8	$ 994.3	$ 42.1	$ 1,005.8	$ (1,727.0)	$936.0
Investing activities						
Capital expenditures	(0.5)	—	—	(329.9)	—	(330.4)
Contributions to unconsolidated affiliates	—	—	(83.0)	(4.7)	—	(87.7)
Other investing activities	—	—	11.2	12.3	—	23.5
Cash used in investing activities	(0.5)	—	(71.8)	(322.3)	—	(394.6)
Financing activities						
Dividends paid	(543.4)	(999.0)	(999.0)	—	1,998.0	(543.4)
Distributions to noncontrolling interests	—	—	—	(4.1)	(271.0)	(275.1)
Intercompany borrowings (advances), net	(2,376.9)	2,022.2	1,028.3	(673.6)	—	—
Borrowing (repayment) of short-term borrowings, net	932.3	(1,110.3)	—	—	—	(178.0)
Issuance of long-term debt, net of discounts	1,190.1	—	—	—	—	1,190.1
Repayment of long-term debt	(87.1)	(900.0)	—	(5.8)	—	(992.9)
Issuance of common stock	45.8	—	—	—	—	45.8
Other	(17.9)	(7.2)	—	—	—	(25.1)
Cash provided by (used in) financing activities	(857.1)	(994.3)	29.3	(683.5)	1,727.0	(778.6)
Change in cash and cash equivalents	(236.8)	—	(0.4)	—	—	(237.2)
Cash and cash equivalents at beginning of period	248.5	—	0.4	—	—	248.9
Cash and cash equivalents at end of period	$11.7	$ —	$ —	$ —	$ —	$11.7

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(Unaudited)	Nine Months Ended September 30, 2016 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$546.3	$ 998.3	$ 52.3	$ 916.7	$ (1,591.6)	$922.0
Investing activities						
Capital expenditures	(0.1)	—	—	(491.4)	—	(491.5)
Other investing activities	—	—	30.0	(23.1)	—	6.9
Cash provided by (used in) investing activities	(0.1)	—	30.0	(514.5)	—	(484.6)
Financing activities						
Dividends paid	(388.1)	(999.0)	(999.0)	—	1,998.0	(388.1)
Distributions to noncontrolling interests	—	—	—	(6.1)	(406.4)	(412.5)
Intercompany borrowings (advances), net	(33.1)	(493.7)	917.1	(390.3)	—	—
Borrowing (repayment) of short-term borrowings, net	—	147.2	—	—	—	147.2
Issuance of long-term debt, net of discounts	—	1,000.0	—	—	—	1,000.0
Debt financing costs	—	(2.8)	—	—	—	(2.8)
Repayment of long-term debt	(0.3)	(650.0)	—	(5.8)	—	(656.1)
Issuance of common stock	14.9	—	—	—	—	14.9
Cash used in financing activities	(406.6)	(998.3)	(81.9)	(402.2)	1,591.6	(297.4)
Change in cash and cash equivalents	139.6	—	0.4	—	—	140.0
Change in cash and cash equivalents included in discontinued operations	(0.2)	—	—	—	—	(0.2)
Change in cash and cash equivalents included in continuing operations	139.4	—	0.4	—	—	139.8
Cash and cash equivalents at beginning of period	92.5	—	5.1	—	—	97.6
Cash and cash equivalents at end of period	$231.9	$ —	$ 5.5	$ —	$ —	$237.4

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited Consolidated Financial Statements and the Notes to Consolidated Financial Statements in this Quarterly Report, as well as our Annual Report and our Current Report on Form 8-K filed on July 6, 2017, which updates Item 8 in our 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 Quarterly Report for additional information.

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

Business Update and Market Conditions - We operate predominantly fee-based businesses in each of our three reportable segments and expect our consolidated earnings to be approximately 90 percent fee-based for the remainder of 2017. In the first nine months of 2017, our Natural Gas Gathering and Processing segment's fee revenues averaged 86 cents per MMBtu, compared with an average of 73 cents per MMBtu in the same period in 2016, due to our contract restructuring efforts to mitigate commodity price risk and increasing volumes on those contracts with higher contracted fees. Volumes gathered and processed increased across our asset footprint in our Natural Gas Gathering and Processing segment for the nine months ended September 30, 2017, compared with the same period in 2016. We connected six third-party natural gas processing plants in our Natural Gas Liquids segment in the first nine months of 2017, which contributed to higher gathered NGL volumes in the third quarter 2017, compared with the first two quarters of 2017 and the full year 2016. We expect additional NGL volume growth as these plants increase production. Our fee-based transportation services in our Natural Gas Pipelines segment increased in the first nine months of 2017, compared with the same period in 2016, due primarily to higher firm transportation capacity contracted from the WesTex pipeline expansion.

We continue to expect demand for our midstream services and infrastructure development to be primarily driven by producers who need to connect production with end-use markets where current infrastructure is insufficient. We also expect additional demand for our services to support increased demand for NGL products from the petrochemical industry and NGL exporters, and increased demand for natural gas from exports and power plants previously fueled by coal.

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

STACK and SCOOP - We expect each of our business segments to benefit from increased production in the Mid-Continent region from the highly productive STACK and SCOOP areas where there was an increase in producer activity in late 2016 and the first nine months of 2017, which we expect to continue into 2018. In June and July 2017, we announced additional growth projects supported by long-term primarily fee-based contracts, minimum volume commitments and acreage dedications to serve the expected growth and needs of our natural gas processors and producer customers. We announced plans to expand our Canadian Valley natural gas processing facility to 400 MMcf/d from 200 MMcf/d and related gathering infrastructure in the STACK area of Oklahoma, which is expected to cost approximately $155 million to $165 million and be completed by the end of 2018. We also announced plans to connect our natural gas gathering systems in the STACK area of Oklahoma to an existing third-party processing facility, accessing 200 MMcf/d of processing capacity by constructing a 30-mile natural gas gathering pipeline and related infrastructure. This project is expected to cost approximately $40 million and be completed by the end of 2017. Following the completion of these projects, our total natural gas processing capacity in Oklahoma will be approximately 1.1 Bcf/d. These projects are expected to contribute incremental volume to our natural gas liquids gathering system. To accommodate increased NGL volumes in the area, we announced plans to expand our natural gas liquids gathering system in

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the Mid-Continent region and our existing Sterling III Pipeline, which are backed by a long-term contract. We expect to invest approximately $130 million for these NGL projects, which are expected to be completed by the end of 2018.

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

In our Natural Gas Gathering and Processing segment, we have more than 300,000 acres dedicated to us in the STACK and SCOOP areas. In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the STACK and SCOOP areas. We are connected to more than 110 third-party natural gas processing plants in the Mid-Continent region and have connected three additional third-party natural gas processing plants in 2017. In our Natural Gas Pipelines segment, we are connected to more than 30 natural gas processing plants in Oklahoma, which have a total processing capacity of approximately 1.8 Bcf/d, and are expanding our ONEOK Gas Transmission Pipeline by 100 MMcf/d to provide increased westbound transportation services from the STACK and SCOOP areas.

Rocky Mountain Region - We expect each of our business segments to benefit from increased production in the Williston Basin, where there was an increase in producer activity in late 2016 and through the first nine months of 2017, which we expect to continue into 2018. In our Natural Gas Gathering and Processing segment, our completed growth projects, including our Bear Creek natural gas processing plant and infrastructure project that was completed in August 2016, have increased our gathering and processing capacity and allow us to capture natural gas from wells that previously flared natural gas production. We have available natural gas processing capacity in this basin of approximately 150 MMcf/d. In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the Williston Basin with connections to more than 10 natural gas processing plants, both third-party and our own. We connected one new third-party natural gas processing plant in the Rocky Mountain region in the first quarter 2017. In our Natural Gas Pipelines segment, our 50 percent-owned Northern Border Pipeline is well positioned to transport natural gas from processing plants in the Williston Basin to end-use markets and is substantially contracted through the first quarter 2020.

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

In our Natural Gas Liquids segment, we are well-positioned in the Permian Basin and are connected to nearly 40 third-party natural gas processing plants through our WTLPG joint venture, where we connected one third-party natural gas processing plant in the third quarter 2017 and one in the first quarter 2017. In October 2017, we announced that our WTLPG joint venture, in which we own an 80 percent interest, plans to extend its pipeline system into the core of the Delaware Basin, which includes construction of a 120-mile pipeline lateral and related infrastructure to support an initial capacity of 110 MBbl/d. The project is supported by long-term dedicated NGL production from two planned third-party natural gas processing plants and positions the West Texas LPG pipeline for significant future NGL volume growth. The project is expected to cost approximately $200 million and be completed by the third quarter of 2018. In our Natural Gas Pipelines segment, we believe we are well-positioned in the Delaware Basin and have a significant position in the Midland Basin. We are connected to more than 25 natural gas processing plants serving the Permian Basin, which have a total processing capacity of approximately 1.9 Bcf/d. The Roadrunner pipeline transports natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas, and is fully subscribed with 25-year firm demand charge, fee-based agreements. The Roadrunner pipeline connects with our existing natural gas pipeline and storage infrastructure in Texas and, together with our WesTex intrastate natural gas pipeline expansion project, creates a platform for future opportunities to deliver natural gas supply to Mexico.

Ethane Opportunity - Ethane rejection levels across our system averaged more than 150 MBbl/d in the first nine months of 2017, which is slightly lower than the same period in 2016. We expect ethane recovery levels to continue to fluctuate as the price differential between ethane and natural gas changes. We expect ethane recovery levels to increase initially in regions closest to market centers such as the Permian Basin and Mid-Continent region, as ethylene producers complete their expansion projects and NGL exporters increase their export volumes. We expect future increases in ethane recovery to have a favorable impact on NGL volumes and our financial results.

Equity Issuances - 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’

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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. In September and October 2017, we sold 3.3 million shares of common stock through our “at-the-market” equity program that resulted in net proceeds of $184.2 million.

Dividends - In October 2017, we declared a dividend of $0.745 per share ($2.98 per share on an annualized basis) for shareholders of record at the close of business on November 6, 2017, payable November 14, 2017, which represents an increase of 21 percent compared with the same period in the prior year. Our dividend growth is due in part to the increase in cash flows resulting from the Merger Transaction.

Hurricane Harvey - During August and September 2017, Hurricane Harvey caused disruptions to our Natural Gas Liquids segment exchange services business in the Mid-Continent and Gulf Coast regions. While our assets did not experience any significant damage, some of our assets in the Gulf Coast and Mid-Continent areas briefly operated at reduced volumes following the hurricane due primarily to temporary refinery and petrochemical facility outages and constraints on our customers’ ability to receive NGL products. Without this disruption, we estimate operating income and adjusted EBITDA would have been approximately $4.5 million higher.

Goodwill Impairment Review - We assess our goodwill for impairment at least annually as of July 1. At July 1, 2017, we assessed qualitative factors to determine whether it was more likely than not that the fair value of each of our reporting units was less than its carrying amount. After assessing qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance), we determined that it was more likely than not that the fair value of each reporting unit was greater than its respective carrying value, that no further testing was necessary and that goodwill was not considered impaired.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

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

Financial Results	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Three Months 2017 vs. 2016 Increase (Decrease)		Nine Months 2017 vs. 2016 Increase (Decrease)	
	(Millions of dollars)							
Revenues								
Commodity sales	$2,322.5	$1,840.5	$6,700.3	$4,757.3	$482.0	26 %	$1,943.0	41 %
Services	583.8	517.4	1,681.5	1,509.2	66.4	13 %	172.3	11 %
Total revenues	2,906.3	2,357.9	8,381.8	6,266.5	548.4	23 %	2,115.3	34 %
Cost of sales and fuel (exclusive of items shown separately below)	2,229.4	1,751.6	6,464.3	4,474.7	477.8	27 %	1,989.6	44 %
Operating costs	207.0	184.1	616.7	553.0	22.9	12 %	63.7	12 %
Depreciation and amortization	102.3	98.5	302.6	292.2	3.8	4 %	10.4	4 %
Impairment of long-lived assets	16.0	—	16.0	—	16.0	*	16.0	*
(Gain) loss on sale of assets	(0.3)	(5.7)	(0.9)	(9.5)	(5.4)	(95%)	(8.6)	(91%)
Operating income	$351.9	$329.4	$983.1	$956.1	$22.5	7 %	$27.0	3 %
Equity in net earnings from investments	$40.1	$35.2	$119.0	$100.4	$4.9	14 %	$18.6	19 %
Impairment of equity investments	$(4.3)	$—	$(4.3)	$—	$4.3	*	$4.3	*
	$(126.5)	$(118.2)	$(361.5)	$(355.5)	$8.3	7 %	$6.0	2 %

Interest expense, net of capitalized interest								
Net income	$166.5	$194.2	$528.7	$549.0	$(27.7)	(14%)	$(20.3)	(4 %)
Adjusted EBITDA	$517.2	$469.7	$1,439.1	$1,375.9	$47.5	10 %	$63.2	5 %
Capital expenditures	$135.2	$158.3	$330.4	$491.5	$(23.1)	(15%)	$(161.1)	(33%)

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

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

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Operating income and adjusted EBITDA increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to higher revenues resulting from volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment, higher transportation services due to increased firm demand charge contracted capacity in our Natural Gas Pipelines segment and higher optimization and marketing earnings due primarily to wider product price differentials in our Natural Gas Liquids segment. These increases were offset partially by higher operating costs related to the timing of routine maintenance projects in our Natural Gas Liquids and Natural Gas Pipelines segments and higher labor and employee-related costs associated with our benefit plans and the growth of our operations. Operating income was also impacted in the three and nine months ended September 30, 2017, compared with the same periods in 2016, by $16.0 million of noncash impairment charges related to nonstrategic assets in our Natural Gas Gathering and Processing segment. In the nine months ended September 30, 2017, we incurred a $20 million noncash expense related to our Series E Preferred Stock contribution to the Foundation and operating costs related to the Merger Transaction of approximately $29.5 million.

Equity in net earnings from investments increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to higher firm transportation revenues related to Roadrunner’s Phase II capacity, which was placed in service in October 2016. Roadrunner is fully subscribed under long-term firm demand charge contracts. We recorded $4.3 million of noncash impairment charges related to a nonstrategic equity investment in our Natural Gas Gathering and Processing segment.

Capital expenditures decreased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to growth projects placed in service in 2016.

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

Natural Gas Gathering and Processing

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

The Williston Basin, which is located in portions of North Dakota and Montana, including the oil-producing, NGL-rich Bakken Shale and Three Forks formations, is an active drilling region. Our completed growth projects in the Williston Basin, including our Bear Creek natural gas processing plant and infrastructure project that was completed in August 2016, have increased our gathering and processing capacity and allow us to capture natural gas from wells that previously flared natural gas production. The Mid-Continent region is an active drilling region and includes the oil-producing NGL-rich STACK and SCOOP areas in the Anadarko Basin 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. The Powder River Basin is primarily located in Wyoming, which includes the NGL-rich Niobrara Shale and Frontier, Turner and Sussex formations where we provide gathering and processing services to customers in the southeast portion of Wyoming.

Revenues for this segment are derived primarily from POP with fee contracts and fee-only contracts. Under a POP with fee contract, we charge fees for gathering, treating, compressing and processing the producer’s natural gas. We also generally purchase the producer’s raw natural gas, which we process into residue natural gas and NGLs, then we sell these commodities and associated condensate to downstream customers. We remit sales proceeds to the producer according to the contractual terms and retain our portion. Additionally, 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. With a fee-only contract, we are paid a fee for the services we provide, based on volumes gathered, processed, treated and/or compressed.

We have restructured many of our contracts to significantly increase our fees, and as a result of these restructured contracts, our Natural Gas Gathering and Processing segment’s earnings are primarily fee-based. Our direct commodity price sensitivity in this segment has decreased as a result of these restructured contracts. To mitigate the impact of our remaining commodity price exposure, we have hedged a significant portion of our Natural Gas Gathering and Processing segment’s commodity price risk

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for the remainder of 2017 and 2018. This segment has substantial acreage dedications in some of the most productive areas of the Williston Basin and Mid-Continent region, specifically the STACK and SCOOP, which helps to mitigate volumetric risk.

Our natural gas gathered and processed volumes in the Williston Basin increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to new supply and completion of growth projects, offset partially by the impact of severe winter weather in the first quarter 2017 and natural production declines from existing wells. Williston Basin volumes are expected to continue to grow in the remainder of 2017 and in 2018 due to the following:

- producers focusing their drilling and completion in the most productive areas in which we have substantial acreage dedications and significant gathering and processing assets;
- continued improvements in production by producers due to enhanced completion techniques and more efficient drilling rigs; offset partially by
- natural production declines.

In the Mid-Continent region, we have significant natural gas gathering and processing assets in Oklahoma and Kansas. We have seen increased producer activity in the STACK and SCOOP areas, where we have substantial acreage dedications. We had higher natural gas gathered and processed volumes in the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to new production. These increases were offset partially by natural production declines from existing wells. We expect our natural gas volumes to continue to grow into 2018 due to producer drilling and completion activity, offset partially by the natural production declines from existing wells connected to our system.

Growth Projects - Our Natural Gas Gathering and Processing segment is investing in growth projects in NGL-rich areas, including the Bakken Shale and Three Forks formation in the Williston Basin and STACK and SCOOP areas of the Anadarko Basin, that we expect will enable us to meet the needs of crude oil and natural gas producers in those areas. In 2017, these investments are primarily in the form of new well connections and related infrastructure.

In July 2017, we announced plans to expand our Canadian Valley natural gas processing facility to 400 MMcf/d from 200 MMcf/d and related gathering infrastructure in the STACK area of Oklahoma. This project is expected to be complete by the end of 2018 at a cost of $155 million to $165 million, excluding capitalized interest, and is supported by long-term primarily fee-based contracts, minimum volume commitments and acreage dedications.

In June 2017, we announced plans to connect our natural gas gathering systems in the STACK area of Oklahoma to an existing third-party processing facility, accessing 200 MMcf/d of processing capacity by constructing a 30-mile natural gas gathering pipeline and related infrastructure through the core of the STACK area. This project is expected to be complete by the end of 2017 at a cost of $40 million, excluding capitalized interest, and is supported by long-term acreage dedications.

In August 2016, we completed the 80 MMcf/d Bear Creek processing plant and related infrastructure project in the Williston Basin for approximately $240 million, excluding capitalized interest.

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

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Selected Financial Results - The following table sets forth certain selected financial results for our Natural Gas Gathering and Processing segment for the periods indicated:

Financial Results	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Three Months 2017 vs. 2016 Increase (Decrease)		Nine Months 2017 vs. 2016 Increase (Decrease)	
	(Millions of dollars)							
NGL sales	$316.7	$134.9	$796.0	$381.9	$181.8	*	$414.1	*
Condensate sales	23.0	13.8	63.9	41.4	9.2	67 %	22.5	54 %
Residue natural gas sales	218.8	186.8	645.1	481.1	32.0	17 %	164.0	34 %
Gathering, compression, dehydration and processing fees and other revenue	224.4	176.7	625.0	516.6	47.7	27 %	108.4	21 %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(567.0)	(336.5)	(1,544.3)	(902.7)	230.5	68 %	641.6	71 %
Operating costs	(80.2)	(69.4)	(225.1)	(208.4)	10.8	16 %	16.7	8 %
Equity in net earnings from investments; excluding noncash impairment charges	3.4	2.6	9.8	8.0	0.8	31 %	1.8	23 %
Other	2.9	0.9	3.8	2.3	2.0	*	1.5	65 %
Adjusted EBITDA	$142.0	$109.8	$374.2	$320.2	$32.2	29 %	$54.0	17 %
Capital expenditures	$85.5	$99.6	$185.7	$325.8	$(14.1)	(14%)	$(140.1)	(43%)

* Percentage change is greater than 100 percent

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

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

Adjusted EBITDA increased $32.2 million for the three months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

- an increase of $26.5 million due primarily to natural gas volume growth in the Williston Basin and the STACK and SCOOP areas, offset partially by natural production declines; and
- an increase of $16.9 million due primarily to restructured contracts resulting in higher fee revenues from increased average fee rates, offset partially by a lower percentage of proceeds retained from the sale of commodities purchased under our POP with fee contracts; offset partially by
- an increase of $10.8 million in operating costs due primarily to increased labor and employee-related costs associated with our benefit plans and the growth of our operations and timing of ad valorem tax accruals; and
- a decrease of $3.1 million due primarily to lower realized natural gas and condensate prices.

Adjusted EBITDA increased $54.0 million for the nine months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

- an increase of $46.8 million due primarily to restructured contracts resulting in higher fee revenues from increased average fee rates, offset partially by a lower percentage of proceeds retained from the sale of commodities purchased under our POP with fee contracts; and
- an increase of $28.2 million due primarily to natural gas volume growth in the Williston Basin and the STACK and SCOOP areas, offset partially by natural production declines and the impact of severe winter weather in the first quarter 2017; offset partially by
- an increase of $16.7 million in operating costs due primarily to increased labor and employee-related costs associated with our benefit plans and the growth of our operations; and
- a decrease of $7.5 million due primarily to lower realized natural gas and condensate prices.

Capital expenditures decreased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to growth projects placed in service in 2016.

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

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Selected Operating Information - The following table sets forth selected operating information for our Natural Gas Gathering and Processing segment for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information (a)	2017	2016	2017	2016
Natural gas gathered (BBtu/d)	2,278	1,977	2,147	2,047
Natural gas processed (BBtu/d) (b)	2,128	1,829	1,995	1,886
NGL sales (MBbl/d)	193	153	184	155
Residue natural gas sales (BBtu/d)	955	837	869	877
Realized composite NGL net sales price ($/gallon) (c) (d)	$0.24	$0.23	$0.22	$0.22
Realized condensate net sales price ($/Bbl) (c) (e)	$33.83	$41.13	$33.07	$36.91
Realized residue natural gas net sales price ($/MMBtu) (c) (e)	$2.51	$2.84	$2.53	$2.76
Average fee rate ($/MMBtu)	$0.86	$0.76	$0.86	$0.73

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

Natural gas gathered, natural gas processed, NGL sales and residue natural gas sales increased during the three months ended September 30, 2017, compared with the same period in 2016, due to the completion of growth projects and new supply in the Williston Basin and STACK and SCOOP areas, offset partially by natural production declines on existing wells.

Natural gas gathered, natural gas processed and NGL sales increased during the nine months ended September 30, 2017, compared with the same period in 2016, due to the completion of growth projects and new supply in the Williston Basin and STACK and SCOOP areas, offset by natural production declines on existing wells and the impact of severe winter weather in the first quarter 2017. Residue natural gas sales decreased due primarily to increased ethane recovery, which also contributed to increased NGL sales.

The quantity and composition of NGLs and natural gas have varied as new plants were placed in service and to ensure natural gas and natural gas liquids pipeline specifications were met.

Commodity Price Risk - See discussion regarding our commodity price risk and our expected equity volumes under “Commodity Price Risk” in Item 3, Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report.

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 where we provide midstream services to producers of NGLs and deliver those products to the two primary market centers, one in the Mid-Continent in Conway, Kansas, and the other in the Gulf Coast in Mont Belvieu, Texas. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, New Mexico, Montana, North Dakota, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. The majority of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas Panhandle are connected to our natural gas liquids gathering systems. We own and operate truck- and rail-loading and -unloading facilities connected to our natural gas liquids fractionation and pipeline assets.

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

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

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

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

Supply growth has resulted in available ethane supply that is greater than the petrochemical industry’s current demand. Low or unprofitable price differentials between ethane and natural gas have resulted in varied levels of ethane rejection at most of our and our customers’ natural gas processing plants connected to our NGL system in the Mid-Continent and Rocky Mountain regions, which also reduced the ethane component of natural gas liquids volumes gathered, fractionated, transported and sold across our assets. Ethane rejection levels across our system averaged more than 150 MBbl/d in the first nine months of 2017, which is slightly lower than the same period in 2016. We expect ethane recovery levels to continue to fluctuate as the price differential between ethane and natural gas changes. We expect ethane recovery levels to increase, initially in regions closest to market centers such as the Permian Basin and Mid-Continent region, as ethylene producers complete their expansion projects and NGL exporters increase their export volumes.

Our Natural Gas Liquids segment’s integrated assets enable us to mitigate partially the impact of ethane rejection through minimum volume commitments, contract modifications that vary fees for ethane and other NGL products, and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials, when they exist, in our optimization activities.

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

Our Natural Gas Liquids segment invests in NGL-related projects to accommodate the transportation, fractionation and storage of NGL supply from shale and other resource development areas across our asset base, to alleviate expected infrastructure constraints between the Mid-Continent and Gulf Coast market centers and to meet increasing petrochemical industry and NGL export demand in the Gulf Coast. We continue to evaluate opportunities to increase the capacity of our assets such as the Bakken, Sterling, Arbuckle and West Texas LPG Pipelines or construct new assets to connect supply growth from the Williston Basin, Mid-Continent and Permian Basin with end-use markets. These expansion opportunities include potential projects which could be in addition to, or replace, our previously announced expansion of the Bakken NGL Pipeline to 160 MBbl/d.

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

In August 2016, we completed the Bear Creek NGL infrastructure project in the Williston Basin for approximately $45 million, excluding AFUDC.

In June 2017, we announced plans to expand our natural gas liquids gathering system in the Mid-Continent and our existing Sterling III Pipeline. These expansions, which are backed by a long-term contract, will help accommodate expected volume growth from current and future natural gas processing plants in the STACK area. Expansions include increasing capacity on the Sterling III Pipeline to 250 MBbl/d from 190 MBbl/d and connecting our Arbuckle Pipeline to a third-party pipeline, which transports NGLs to petrochemical and refining markets in Louisiana. We expect to invest approximately $130 million, excluding capitalized interest, for these projects, which are expected to be completed by the end of 2018.

In October 2017, we announced that our WTLPG joint venture, in which we own an 80 percent interest, plans to extend its pipeline system into the core of the Delaware Basin, which includes construction of a 120-mile pipeline lateral and related infrastructure to support an initial capacity of 110 MBbl/d. The project is supported by long-term dedicated NGL production from two planned third-party natural gas processing plants and positions the West Texas LPG pipeline for significant future NGL volume growth. The project is expected to cost approximately $200 million, excluding capitalized interest, and be completed by the third quarter of 2018.

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

Selected Financial Results - The following table sets forth certain selected financial results for our Natural Gas Liquids segment for the periods indicated:

Financial Results	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Three Months 2017 vs. 2016 Increase (Decrease)		Nine Months 2017 vs. 2016 Increase (Decrease)	
	(Millions of dollars)							
NGL and condensate sales	$2,097.7	$1,649.6	$6,055.0	$4,264.1	$448.1	27 %	$1,790.9	42 %
Exchange service revenues	357.2	338.5	1,046.9	993.3	18.7	6 %	53.6	5 %
Transportation and storage revenues	47.0	51.2	141.8	141.2	(4.2)	(8 %)	0.6	— %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(2,136.2)	(1,694.2)	(6,188.5)	(4,376.3)	442.0	26 %	1,812.2	41 %
Operating costs	(90.2)	(79.8)	(256.3)	(236.7)	10.4	13 %	19.6	8 %
Equity in net earnings from investments	15.3	14.0	44.1	41.2	1.3	9 %	2.9	7 %
Other	3.1	—	2.5	(0.8)	3.1	*	3.3	*
Adjusted EBITDA	$293.9	$279.3	$845.5	$826.0	$14.6	5 %	$19.5	2 %
Capital expenditures	$27.0	$30.5	$59.8	$85.5	$(3.5)	(11%)	$(25.7)	(30%)

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

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

Adjusted EBITDA increased $14.6 million for the three months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

- an increase of $17.4 million in exchange services due to increased volumes in the Williston Basin and the STACK and SCOOP areas from recently connected natural gas processing plants, offset partially by lower volumes in the Granite Wash and Barnett Shale and reduced volumes related to Hurricane Harvey; and
- an increase of $7.5 million in optimization and marketing due primarily to wider product price differentials; offset partially by

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- an increase of $10.4 million in operating costs due primarily to higher ad valorem taxes, higher labor and employee-related costs associated with our benefit plans, the timing of routine maintenance projects and additional operating costs related to Hurricane Harvey; and
- a decrease of $4.2 million in transportation and storage services due primarily to lower storage volumes.

Adjusted EBITDA increased $19.5 million for the nine months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

- an increase of $29.8 million in exchange services due to increased volumes in the Williston Basin and STACK and SCOOP areas from recently connected natural gas processing plants, offset partially by decreased volumes in the Granite Wash and Barnett Shale and reduced volumes related to Hurricane Harvey;
- an increase of $2.9 million in equity in net earnings from investments due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline; and
- an increase of $1.8 million in optimization and marketing due primarily to higher optimization volumes and wider product price differentials; offset partially by
- an increase of $19.6 million in operating costs due primarily to higher ad valorem taxes, labor and employee-related costs associated with our benefit plans, timing of routine maintenance projects and additional operating costs related to Hurricane Harvey.

During August and September 2017, Hurricane Harvey caused disruptions to our exchange services business in the Mid-Continent and Gulf Coast regions. While our assets did not experience any significant damage, some of our assets in the Gulf Coast and Mid-Continent areas briefly operated at reduced volumes following the hurricane due primarily to temporary refinery and petrochemical facility outages and constraints on our customers' ability to receive NGL products. Our operating costs were also higher during this period due primarily to equipment rental and outside services related to maintaining operations of our assets during and immediately after the hurricane. We estimate that our operating income and adjusted EBITDA were adversely impacted by approximately $4.5 million due to these reduced volumes and increased operating costs.

Capital expenditures decreased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to completed growth projects.

Selected Operating Information - The following table sets forth selected operating information for our Natural Gas Liquids segment for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information	2017	2016	2017	2016
NGLs transported-gathering lines (MBbl/d) (a)	812	775	794	778
NGLs fractionated (MBbl/d) (b)	605	606	600	588
NGLs transported-distribution lines (MBbl/d) (a)	569	521	559	504
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix ($/gallon)	$0.05	$0.03	$0.04	$0.03

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

NGLs transported on gathering lines increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due to increased volumes from new plant connections primarily in the Williston Basin, increased Mid-Continent volumes gathered from the STACK and SCOOP areas and increased ethane production, which were offset partially by decreased volumes in the Granite Wash and Barnett Shale.

NGLs fractionated increased for the nine months ended September 30, 2017, compared with the same period in 2016, due primarily to an increase in gathered volumes in the Williston Basin and STACK and SCOOP areas and increased volumes from fractionation-only contracts. NGLs fractionated were relatively unchanged for the three months ended September 30, 2017, compared with the same period in 2016, due partially to the impact of Hurricane Harvey.

NGLs transported on distribution lines increased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to increased volumes transported for our optimization activities.

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Natural Gas Pipelines

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

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

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

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

Transportation Rates - Our transportation contracts for our regulated natural gas services are based upon rates stated in the respective tariffs. The tariffs provide both the general terms and conditions for the facilities and the maximum allowed rates customers can be charged by type of service, which may be discounted to meet competition if necessary. The rates are established at FERC or the appropriate state jurisdictional agencies. Our 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. In addition, we may retain a percentage of fuel in-kind based on the volumes of natural gas transported. 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. Customers typically are assessed fees, such as a commodity charge, and we may retain a specified volume of natural gas in-kind based on their actual usage.

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

Storage Rates - Our 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 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.

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Growth Projects - The WesTex pipeline expansion is a wholly owned project. Roadrunner is a 50 percent-owned equity-method investment project.

WesTex Pipeline Expansion - In October 2016, the WesTex pipeline expansion was completed for approximately $55 million, excluding capitalized interest. This expansion increased the pipeline capacity by 260 MMcf/d.

Roadrunner - Phase I and Phase II of the Roadrunner pipeline were completed in March and October 2016, respectively, for total project costs of approximately $200 million and $210 million, respectively, excluding capitalized interest. The current capacity of Roadrunner is 570 MMcf/d. Construction of Phase III of Roadrunner is planned for completion in 2019, which is expected to increase capacity by 70 MMcf/d and have total project costs of approximately $30 million to $40 million.

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months 2017 vs. 2016		Nine Months 2017 vs. 2016	
Financial Results	2017	2016	2017	2016	Increase (Decrease)		Increase (Decrease)	
	(Millions of dollars)							
Transportation revenues	$81.1	$71.9	$242.0	$208.5	$9.2	13 %	$33.5	16 %
Storage revenues	14.4	13.3	43.7	44.0	1.1	8 %	(0.3)	(1 %)
Natural gas sales and other revenues	10.9	6.9	25.4	13.6	4.0	58 %	11.8	87 %
Cost of sales and fuel (exclusive of depreciation and items shown separately below)	(10.6)	(6.9)	(34.0)	(15.9)	3.7	54 %	18.1	*
Operating costs	(29.8)	(28.4)	(92.5)	(85.1)	1.4	5 %	7.4	9 %
Equity in net earnings from investments	21.3	18.6	65.1	51.2	2.7	15 %	13.9	27 %
Other	0.2	4.9	1.4	6.9	(4.7)	(96%)	(5.5)	(80%)
Adjusted EBITDA	$87.5	$80.3	$251.1	$223.2	$7.2	9 %	$27.9	13 %
Capital expenditures	$18.8	$24.5	$70.7	$71.7	$(5.7)	(23%)	$(1.0)	(1 %)

* Percentage change is greater than 100 percent.

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

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

Adjusted EBITDA increased $7.2 million for the three months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

- an increase of $6.7 million from higher transportation services due primarily to increased firm demand charge contracted capacity; and
- an increase of $2.7 million in equity in net earnings from investments due primarily to higher firm transportation revenues on Roadrunner; offset partially by
- a decrease of $3.6 million due primarily to gains on sales of excess natural gas in storage in 2016; and
- an increase of $1.4 million in operating costs due primarily to higher labor and employee-related costs associated with our benefit plans.

Adjusted EBITDA increased $27.9 million for the nine months ended September 30, 2017, compared with the same period in 2016, primarily as a result of the following:

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an increase of $22.7 million from higher transportation services due primarily to increased firm demand charge contracted capacity;

- an increase of $13.9 million in equity in net earnings from investments due primarily to higher firm transportation revenues on Roadrunner; and
- an increase of $3.2 million from higher net retained fuel due primarily to higher equity gas sales and higher natural gas prices, offset partially by lower natural gas volumes retained; offset partially by;
- a decrease of $8.3 million due primarily to gains on sales of excess natural gas in storage in 2016; and
- an increase of $7.4 million in operating costs due primarily to routine maintenance projects and higher labor and employee-related costs associated with our benefit plans.

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Capital expenditures decreased for the three and nine months ended September 30, 2017, compared with the same periods in 2016, due primarily to the completion of growth projects, offset partially by the timing of maintenance projects.

Selected Operating Information - The following table sets forth selected operating information for our Natural Gas Pipelines segment for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information (a)	2017	2016	2017	2016
Natural gas transportation capacity contracted (MDth/d)	6,593	6,300	6,600	6,240
Transportation capacity subscribed	94 %	95 %	94 %	94 %
Average natural gas price				
Mid-Continent region ($/MMBtu)	$2.57	$2.60	$2.65	$2.12

(a) - Includes volumes for consolidated entities only.

Our natural gas pipelines primarily serve end users, such as natural gas distribution and electric-generation companies, that require natural gas to operate their businesses regardless of location price differentials. The development of shale and other resource areas has continued to increase available natural gas supply, and we expect producers to demand incremental transportation services in the future as additional supply is developed. The abundance of natural gas supply and regulations on emissions from coal-fired electric-generation plants may also increase the demand for our services from electric-generation companies as they convert to a natural gas fuel source. Overall, our contracted transportation capacity and fee-based earnings in this segment increased in connection with the October 2016 completion of our WesTex pipeline expansion.

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

Under the terms of settlement with shippers in 2012, Northern Border Pipeline is required to file a rate case by January 1, 2018. Northern Border Pipeline has reached a settlement-in-principle with shippers, which is expected to be filed with the FERC no later than December 2017. We expect future transportation rates to be lower than current rates, however, we do not expect the resulting decrease in equity earnings and cash distributions from Northern Border Pipeline to be material to us.

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

Adjusted EBITDA

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

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A reconciliation of net income from continuing operations, the nearest comparable GAAP financial performance measure, to adjusted EBITDA for the three and nine months ended September 30, 2017 and 2016, is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Reconciliation of income from continuing operations to adjusted EBITDA	(Thousands of dollars)			
Income from continuing operations	$166,531	$194,792	$528,707	$550,789
Add:				
Interest expense, net of capitalized interest	126,533	118,240	361,468	355,463
Depreciation and amortization	102,298	98,550	302,566	292,275
Income taxes	97,128	55,012	195,913	157,536
Impairment charges	20,240	—	20,240	—
Noncash compensation expense	4,883	3,165	9,790	20,170
Other noncash items and equity AFUDC (a)	(420)	(61)	20,450	(375)
Adjusted EBITDA	$517,193	$469,698	$1,439,134	$1,375,858
Reconciliation of segment adjusted EBITDA to adjusted EBITDA				
Segment adjusted EBITDA:				
Natural Gas Gathering and Processing	$141,950	$109,837	$374,178	$320,170
Natural Gas Liquids	293,919	279,256	845,457	826,036
Natural Gas Pipelines	87,527	80,304	251,145	223,185
Other (b)	(6,203)	301	(31,646)	6,467
Adjusted EBITDA	$517,193	$469,698	$1,439,134	$1,375,858

(a) - Nine months ended September 30, 2017, includes our April 2017 contribution to the Foundation of 20,000 shares of Series E Preferred Stock, with an aggregate value of $20 million.

(b) - Nine months ended September 30, 2017, includes Merger Transaction costs of $29.5 million.

CONTINGENCIES

See Note K of the Notes to Consolidated Financial Statements in this Quarterly Report for a discussion of developments concerning the Gas Index Pricing Litigation and the ONEOK Partners Class Action Litigation.

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

LIQUIDITY AND CAPITAL RESOURCES

General - Historically, our primary source of cash inflows were distributions to us from our general partner and limited partner interests in ONEOK Partners. Beginning in the third quarter 2017, as a result of the completion of the Merger Transaction, our cash flow sources and requirements significantly changed. We now rely primarily on operating cash flows, commercial paper, bank credit facilities, debt issuances and the issuance of common stock for our liquidity and capital resources requirements. In addition, we expect increased cash outflows related to i) capital expenditures, which were previously funded by ONEOK Partners and ii) dividends paid to shareholders, due to the increase in the number of shares outstanding as a result of the close of the Merger Transaction and higher anticipated dividends per share, subject to ONEOK board approval.

We expect our sources of cash inflow to provide sufficient resources to finance our operations and quarterly cash dividends, including expected future dividend increases. To the extent operating cash flows are not sufficient to fund our dividends, we may utilize short- and long-term debt and issuances of equity, as necessary or appropriate. We may access the capital markets to issue debt or equity securities as we consider prudent to provide liquidity to refinance existing debt, improve credit metrics or to fund capital expenditures.

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

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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 - Beginning in the third quarter 2017, as a result of the completion of the Merger Transaction, our principal sources of short-term liquidity consist of cash generated from operating activities, distributions received from our equity-method investments and proceeds from our commercial paper program, our 2017 Credit Agreement and our “at-the-market” equity program. Historically, our primary sources of short-term liquidity were quarterly distributions to us from our general partner and limited partner interests in ONEOK Partners, cash on hand and access to our previous $300 million ONEOK Credit Agreement.

We had working capital (defined as current assets less current liabilities) deficits of $1.2 billion and $1.4 billion as of September 30, 2017, and December 31, 2016, respectively. Although working capital is influenced by several factors, including, among other things: (i) the timing of (a) scheduled debt payments, (b) the collection and payment of accounts receivable and payable, and (c) equity and debt issuances, and (ii) the volume and cost of inventory and commodity imbalances, our working capital deficit at September 30, 2017, and at December 31, 2016, was driven primarily by current maturities of long-term debt and short-term borrowings. We may have working capital deficits in future periods as we continue to finance our capital-growth projects and repay long-term debt, often initially with short-term borrowings. Our decision to utilize short-term borrowings rather than long-term debt, due to more favorable interest rates, contributes to our working capital deficit. We do not expect this working capital deficit to have an adverse impact to our cash flows or operations.

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

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

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

At September 30, 2017, we had approximately $11.7 million of cash and cash equivalents and approximately $1.6 billion of borrowing capacity under the 2017 Credit Agreement.

For additional information on our 2017 Credit Agreement and commercial paper program, see Note E of the Notes to Consolidated Financial Statements in this Quarterly 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 common stock or long-term notes. Other options to obtain financing include, but are not limited to, 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 July 2017, we completed an underwritten public offering of $1.2 billion senior unsecured notes consisting of $500 million, 4.0 percent senior notes due 2027, and $700 million, 4.95 percent senior notes due 2047. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were approximately $1.18 billion. The proceeds were used for general corporate purposes, which included repayment of existing indebtedness and capital expenditures.

In the first quarter 2016, ONEOK Partners entered into the $1.0 billion Term Loan Agreement with a syndicate of banks and drew the full $1.0 billion available under the agreement. ONEOK Partners used the proceeds to repay $650 million of senior

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notes, which matured in February 2016, to repay amounts outstanding under its commercial paper program and for general partnership purposes. The Term Loan Agreement matures in January 2019 and bears interest at LIBOR plus 130 basis points based on our current credit ratings. In April 2017, ONEOK Partners entered into the first amendment to the Term Loan Agreement which, among other things, added ONEOK as a guarantor to the Term Loan Agreement effective with the closing of the Merger Transaction described in Note B.

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

In July 2017, we redeemed our 6.5 percent senior notes due 2028 at a redemption price of approximately $87 million, including the outstanding principal amount, plus accrued and unpaid interest, with cash on hand.

Also in July 2017, we repaid $500 million of the $1.0 billion Term Loan Agreement due 2019.

For additional information on our consolidated long-term debt, see Note E.

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

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

During the three months ended September 30, 2017, we sold 1.2 million shares of common stock through our "at-the-market" equity program that resulted in net proceeds of approximately $64.7 million, of which $30.8 million had settled as of September 30, 2017. In October 2017, we sold an additional 2.1 million shares of common stock through this program that resulted in net proceeds of $119.5 million. The net proceeds from these issuances were used for general corporate purposes, including repayment of outstanding indebtedness and to fund capital expenditures.

Prior to the close of the Merger Transaction, ONEOK Partners had an "at-the-market" equity program for the offer and sale from time to time of its common units, up to an aggregate amount of $650 million. During the six months ended June 30, 2017, and the year ended December 31, 2016, no common units were sold through ONEOK Partners' "at-the-market" equity program. Upon the close of the Merger Transaction on June 30, 2017, the ONEOK Partners "at-the-market" equity program terminated.

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, short- and long-term debt and the issuance of equity.

Capital expenditures, excluding AFUDC and capitalized interest, were $330.4 million and $491.5 million for the nine months ended September 30, 2017 and 2016, respectively.

We expect our total 2017 growth capital expenditures to range from $450 million to $550 million and our maintenance capital expenditures to range from $130 million to $150 million, excluding AFUDC and capitalized interest. See discussion of our announced growth projects in “Natural Gas Gathering and Processing” and “Natural Gas Liquids” in the “Financial Results and Operating Information” section.

Credit Ratings - Our long-term debt credit ratings as of October 23, 2017, are shown in the table below:

Rating Agency	Rating	Outlook
Moody’s	Baa3	Stable
S&P	BBB	Stable

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

Our credit ratings, which are investment grade, may be affected by a material change in our financial ratios or a material event affecting our business and industry. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. If our credit ratings were downgraded, our cost to borrow funds under the 2017 Credit Agreement would increase and a potential loss of access to the commercial paper market could occur. In the event that we are unable to borrow funds under our commercial paper program and there has not been a material adverse change in our business, we would continue to have access to our 2017 Credit Agreement, which expires in 2022. An adverse credit rating change alone is not a default under our 2017 Credit Agreement. We do not expect a downgrade in our credit rating to have a material impact on our results of operations.

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

Cash Distributions - Prior to the consummation of the Merger Transaction, we received distributions from ONEOK Partners on our common and Class B units and our 2 percent general partner interest, which included our incentive distribution rights. Additional information about ONEOK Partners’ cash distributions and our incentive distribution rights for the periods prior to June 30, 2017, is included under “Cash Distributions” in Note O of the Notes to Consolidated Financial Statements in our Annual Report.
Distributions paid to ONEOK Partners unitholders of record at the close of business on January 30, 2017, and May 1, 2017, were $0.79 per unit. Our incentive distribution rights effectively terminated at the close of the Merger Transaction.

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 on our common stock to shareholders of record at the close of business on January 30, 2017, May 1, 2017, and August 7, 2017, were $0.615, $0.615, and $0.745 per share, respectively. A dividend of $0.745 per share was declared for the shareholders of record at the close of business on November 6, 2017, payable November 14, 2017.

Our Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. In August 2017, we paid dividends of $0.4 million for the Series E Preferred Stock. Dividends totaling approximately $0.3 million were declared for the Series E Preferred Stock and are payable November 14, 2017.

For the nine months ended September 30, 2017 and 2016, cash dividends and distributions paid to noncontrolling interests were sufficiently funded by cash flows from operations.

Pension and Postretirement Benefit Plans - Information about our pension and postretirement benefit plans, including anticipated contributions, is included under Note L of the Notes to Consolidated Financial Statements in our Annual Report. See Note I of the Notes to Consolidated Financial Statements in this Quarterly Report for additional information.

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, noncash expense related to our Series E Preferred Stock contribution to the Foundation, other amounts and changes in our assets and liabilities not classified as investing or financing activities.

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

	Nine Months Ended September 30, 2017	2016	Variances 2017 vs. 2016 Favorable (Unfavorable)
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	$936.0	$922.0	$ 14.0
Investing activities	(394.6)	(484.6)	90.0
Financing activities	(778.6)	(297.4)	(481.2)
Change in cash and cash equivalents	(237.2)	140.0	(377.2)
Change in cash and cash equivalents included in discontinued operations	—	(0.2)	0.2
Change in cash and cash equivalents from continuing operations	(237.2)	139.8	(377.0)
Cash and cash equivalents at beginning of period	248.9	97.6	151.3
Cash and cash equivalents at end of period	$11.7	$237.4	$ (225.7)

Operating Cash Flows - Operating cash flows are affected by earnings from our business activities. 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.

Cash flows from operating activities, before changes in operating assets and liabilities, increased to $1.1 billion for the nine months ended September 30, 2017, compared with $1.0 billion for the same period in 2016. This increase is due primarily to higher revenues resulting from volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment, higher transportation services due to increased firm demand charge contracted capacity in our Natural Gas Pipelines segment and higher optimization and marketing earnings due primarily to wider product price differentials in our Natural Gas Liquids segment, as discussed in "Financial Results and Operating Information."

The changes in operating assets and liabilities decreased operating cash flows $139.8 million for the nine months ended September 30, 2017, compared with a decrease of $112.7 million for the same period in 2016. This change is due primarily to the change in natural gas and NGLs in storage and commodity imbalances, which vary from period to period and vary with changes in commodity prices, the change in risk-management assets and liabilities related to our interest-rate swaps and 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.

Investing Cash Flows - Cash used in investing activities decreased to $394.6 million for the nine months ended September 30, 2017, compared with $484.6 million for the same period in 2016, due primarily to projects placed in service in 2016, offset partially by higher contributions to our unconsolidated affiliates.

Financing Cash Flows - Cash used in financing activities increased to $778.6 million for the nine months ended September 30, 2017, compared with $297.4 million for the same period in 2016, due primarily to repayments of long-term and short-term debt in the nine months ended September 30, 2017.

REGULATORY, ENVIRONMENTAL AND SAFETY MATTERS

Environmental Matters - We are subject to multiple 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 preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. For example, if a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emissions controls and/or other regulatory or permitting mandates under

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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.

Additional information about our regulatory, environmental and safety matters can be found in “Regulatory, Environmental and Safety Matters” under Part I, Item 1, Business, in our Annual Report.

IMPACT OF NEW ACCOUNTING STANDARDS

See Note A of the Notes to Consolidated Financial Statements in this Quarterly Report for discussion of new accounting standards.

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.

Information about our estimates and critical accounting policies is included under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, “Estimates and Critical Accounting Policies,” in our Annual Report.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Quarterly 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 flow and projected levels of distributions), liquidity, management’s plans and objectives for our future growth projects and other future operations (including plans to construct additional natural gas and natural gas liquids pipelines and processing facilities and related cost estimates), our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under federal securities legislation and other applicable laws. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

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

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

- the risk that cost savings, tax benefits and any other synergies from the Merger Transaction may not be fully realized or may take longer to realize than expected;
- the impact and outcome of pending and future litigation, including litigation, if any, relating to the Merger Transaction;
- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;

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- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers' desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas, NGLs and crude oil because of market conditions caused by concerns about climate change;
- the impact of unforeseen changes in interest rates, debt and equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension and postretirement expense and funding resulting from changes in equity and bond market returns;
- our indebtedness and guarantee obligations could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantages compared with our competitors that have less debt, or have other adverse consequences;
- actions by rating agencies concerning our credit.
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving any local, state or federal regulatory body, including the FERC, the National Transportation Safety Board, the PHMSA, the EPA and CFTC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling or extended periods of ethane rejection;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
  - future demand for and prices of natural gas, NGLs and crude oil;
  - competitive conditions in the overall energy market;
  - availability of supplies of Canadian and United States natural gas and crude oil; and
  - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;

- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of uncontracted capacity in our assets being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;

- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part I, Item 1A, Risk Factors, in our most recent Annual Report on Form 10-K 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 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our quantitative and qualitative disclosures about market risk are consistent with those discussed in Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk, in our Annual Report.

COMMODITY PRICE RISK

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

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

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

	Three Months Ending December 31, 2017			
	Volumes Hedged	Average Price		Percentage Hedged
NGLs - excluding ethane (MBbl/d) - Conway/Mont Belvieu	8.0	$0.51	/ gallon	87%
Condensate (MBbl/d) - WTI-NYMEX	1.8	$44.88	/ Bbl	66%
Natural gas (BBtu/d) - NYMEX and basis	72.9	$2.63	/ MMBtu	89%

Year Ending December 31, 2018

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

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	Year Ending December 31, 2019		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (MBbl/d) - Conway/Mont Belvieu	3.4	$0.67 / gallon	33%

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 September 30, 2017. Condensate sales are typically based on the price of crude oil. We estimate the following for our forecasted equity volumes, including the effects of hedging information set forth above, and assuming normal operating conditions:

- a $0.01 per-gallon change in the composite price of NGLs would change adjusted EBITDA for the three months ending December 31, 2017, and for the years ending December 31, 2018, and December 31, 2019, by approximately $0.1 million, $1.9 million and $3.5 million, respectively;
- a $1.00 per-barrel change in the price of crude oil would change adjusted EBITDA for the three months ending December 31, 2017, and for the years ending December 31, 2018, and December 31, 2019, by approximately $0.1 million, $0.5 million and $1.4 million, respectively; and
- a $0.10 per-MMBtu change in the price of residue natural gas would change adjusted EBITDA for the three months ending December 31, 2017, and for the years ending December 31, 2018, and December 31, 2019, by approximately $0.1 million, $0.5 million and $2.8 million, respectively.

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

See Note D of the Notes to Consolidated Financial Statements in this Quarterly Report for more information on our hedging activities.

INTEREST-RATE RISK

We are exposed to interest-rate risk through our 2017 Credit Agreement, commercial paper program, the Term Loan Agreement and long-term debt issuances. Future increases in LIBOR, corporate commercial paper rates or corporate bond rates could expose us to increased interest costs on future borrowings. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. At September 30, 2017, and December 31, 2016, we had forward-starting interest-rate swaps with notional amounts totaling $1.3 billion and $1.2 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances and interest-rate swaps with notional amounts totaling $500 million and $1 billion, respectively, to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges. At September 30, 2017, we had derivative assets of $45.7 million and no derivative liabilities related to these interest-rate swaps. At December 31, 2016, we had derivative assets of $47.5 million and derivative liabilities of $12.8 million related to these interest-rate swaps.

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

See Note D of the Notes to Consolidated Financial Statements in this Quarterly 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 to our Natural Gas Gathering and Processing segment's commodity sales, our Natural Gas Liquids segment's marketing activities and our Natural Gas Pipelines segment's storage activities may be impacted by the low commodity price environment and could experience financial problems, which could result in nonpayment and/or nonperformance, which could adversely impact our results of operations.

Customer concentration - For the nine months ended September 30, 2017, no single customer represented more than 10 percent of our consolidated revenues and only 25 customers individually represented one percent or more of our consolidated revenues,

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the majority of which are investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or secured by letters of credit or other collateral.

Natural Gas Gathering and Processing - Our Natural Gas Gathering and Processing segment's customers are crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. We are not typically exposed to material credit risk with producers under POP with fee contracts as we sell the commodities and remit a portion of the sales proceeds back to the producer customer. For the nine months ended September 30, 2017 and 2016, approximately 95 percent and 99 percent, respectively, of the downstream commodity sales in our Natural Gas Gathering and Processing segment were made to investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or were secured by letters of credit or other collateral.

Natural Gas Liquids - Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. We earn fee-based revenue from NGL and natural gas gathering and processing customers and natural gas liquids pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fee revenues, as we purchase NGLs from our gathering and processing customers and deduct our fee from the amounts we remit. We also earn sales revenue on the downstream sales of NGL products. For the nine months ended September 30, 2017 and 2016, approximately 80 percent and 81 percent, respectively, of our 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, irrigation customers and marketing companies. For the nine months ended September 30, 2017 and 2016, approximately 90 percent and 87 percent, respectively, of our revenues in this segment were from investment-grade customers, as rated by S&P, Moody's or our comparable internal ratings, or were secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Pipelines segment's pipeline tariffs provide us the ability to require security from shippers.

ITEM 4. CONTROLS AND PROCEDURES

Quarterly Evaluation of Disclosure Controls and Procedures - Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Changes in Internal Control Over Financial Reporting - There have been no changes in our internal control over financial reporting during the quarter ended September 30, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Additional information about our legal proceedings is included in Note K of the Notes to Consolidated Financial Statements in this Quarterly Report and under Part I, Item 3, Legal Proceedings, in our Annual Report.

ITEM 1A. RISK FACTORS

Our investors should consider the risks set forth in Part I, Item 1A, Risk Factors, of our Annual Report that could affect us and our business, except for the additional risk factor discussed below. Although we have tried to discuss 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 carefully consider the discussion of risks and the other information included or incorporated by reference in this Quarterly Report, including “Forward-Looking Statements,” which are included in Part I, Item 2, Management’s Discussion and Analysis of Financial Condition and Results of Operations.

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Our consolidated debt and guarantee obligations could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and place us at a competitive disadvantage.

In connection with the Merger Transaction, ONEOK Partners and the Intermediate Partnership entered into agreements guaranteeing our obligations under the 2017 Credit Agreement and our outstanding senior notes and commercial paper, and we entered into agreements guaranteeing ONEOK Partners' obligations under the Term Loan Agreement and its outstanding senior notes. We are therefore liable for these debt obligations of ONEOK Partners in the event of a default. Our indebtedness, along with our guarantee obligations, could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared with our competitors that have less debt and fewer guarantee obligations and/or have other adverse consequences. For more information about our debt, see Note E of the Notes to Consolidated Financial Statements in this Quarterly Report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Readers of this report should not rely on or assume the accuracy of any representation or warranty or the validity of any opinion contained in any agreement filed as an exhibit to this Quarterly Report, because such representation, warranty or opinion may be subject to exceptions and qualifications contained in separate disclosure schedules, may represent an allocation of risk between parties in the particular transaction, may be qualified by materiality standards that differ from what may be viewed as material for securities law purposes, or may no longer continue to be true as of any given date. All exhibits attached to this Quarterly Report are included for the purpose of complying with requirements of the SEC. Other than the certifications made by our officers pursuant to the Sarbanes-Oxley Act of 2002 included as exhibits to this Quarterly Report, all exhibits are included only to provide information to investors regarding their respective terms and should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

The following exhibits are filed as part of this Quarterly Report:

Exhibit No.	Exhibit Description
3.1	Amended and Restated By-laws of ONEOK, Inc. (incorporated by reference from Exhibit 3.1 to ONEOK Inc.'s Current Report on Form 8-K filed February 22, 2017 (File No. 1-13643)).

3.2	Amended and Restated Certificate of Incorporation of ONEOK, Inc., dated May 15, 2008, as amended.
4.1	Fourth Supplemental Indenture, dated as of July 13, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.00 percent Senior Notes due 2027 (incorporated by reference from Exhibit 4.1 to ONEOK Inc.'s Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).
4.2	Fifth Supplemental Indenture, dated as of July 13, 2017, by and among ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and U.S. Bank National Association, as trustee, with respect to the 4.95 percent Senior Notes due 2047 (incorporated by reference from Exhibit 4.2 to ONEOK Inc.'s Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).

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10.1	Underwriting Agreement, dated July 10, 2017, between ONEOK, Inc., ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Mizuho Securities USA LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 from ONEOK, Inc.'s the Current Report on Form 8-K filed July 13, 2017 (File No. 1-13643)).
10.2	Equity Distribution Agreement, dated July 19, 2017, by and among ONEOK, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, BB&T Capital Markets, a division of BB&T Securities, LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Goldman Sachs & Co. LLC, Jefferies LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, RBC Capital Markets, LLC, TD Securities (USA) LLC, UBS Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 from ONEOK, Inc.'s Current Report on Form 8-K filed July 19, 2017 (File No. 1-13643)).
31.1	Certification of Terry K. Spencer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Walter S. Hulse pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Terry K. Spencer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Walter S. Hulse pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
101 INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definitions Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.

Attached as Exhibit 101 to this Quarterly Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the three and nine months ended September 30, 2017 and 2016; (iii) Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2017 and 2016; (iv) Consolidated Balance Sheets at September 30, 2017, and December 31, 2016; (v) Consolidated Statements of Cash Flows for the nine months ended September 30, 2017 and 2016; (vi) Consolidated Statements of Changes in Equity for the nine months ended September 30, 2017 and 2016; and (vii) Notes to Consolidated Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

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SIGNATURE

Pursuant to the requirements 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: November 1, 2017 By: /s/ Walter S. Hulse III
Walter S. Hulse III
Chief Financial Officer and
Executive Vice President, Strategic Planning
and Corporate Affairs
(Principal Financial Officer)