WILLIAMS COMPANIES INC
Form 10-Q
November 01, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549
FORM 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018
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 1-4174
THE WILLIAMS COMPANIES, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	73-0569878
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER TULSA, OKLAHOMA	74172-0172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (918) 573-2000
NO CHANGE

(Former name, former address and former fiscal year, if changed since last report.)
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 þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨	Emerging growth company ¨
		(Do not check if a smaller reporting 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 þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Shares Outstanding at October 29, 2018
Common Stock, $1 par value	1,210,542,031

The Williams Companies, Inc.
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The reports, filings, and other public announcements of The Williams Companies, Inc. (Williams) may contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions, and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "potential," "projects," "scheduled," "will," "assumes," "guidance," "outlook," "in-service date," or other similar expressions. forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Levels of dividends to Williams stockholders;

- Future credit ratings of Williams and its affiliates;

- Amounts and nature of future capital expenditures;

- Expansion and growth of our business and operations;

- Expected in-service dates for capital projects;
- Financial condition and liquidity;
- Business strategy;
- Cash flow from operations or results of operations;
- Seasonality of certain business components;
- Natural gas and natural gas liquids prices, supply, and demand;
- Demand for our services.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Whether we are able to pay current and expected levels of dividends;
- Whether we will be able to effectively execute our financing plan;
- Availability of supplies, market demand, and volatility of prices;
- Inflation, interest rates, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on customers and suppliers);
- The strength and financial resources of our competitors and the effects of competition;
- Whether we are able to successfully identify, evaluate and timely execute investment opportunities;
- Our ability to acquire new businesses and assets and successfully integrate those operations and assets into existing businesses as well as successfully expand our facilities, and to consummate asset sales on acceptable terms;
- Development and rate of adoption of alternative energy sources;
- The impact of operational and developmental hazards and unforeseen interruptions;
- The impact of existing and future laws (including, but not limited to, the Tax Cuts and Job Acts of 2017 and Colorado Proposition 112), regulations, the regulatory environment, environmental liabilities, and litigation, as well as our ability to obtain necessary permits and approvals, and achieve favorable rate proceeding outcomes;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;

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- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers and counterparties;
- Risks related to financing, including restrictions stemming from debt agreements, future changes in credit ratings as determined by nationally recognized credit rating agencies, and the availability and cost of capital;
- The amount of cash distributions from and capital requirements of our investments and joint ventures in which we participate;
- Risks associated with weather and natural phenomena, including climate conditions and physical damage to our facilities;
- Acts of terrorism, cybersecurity incidents, and related disruptions;
- Additional risks described in our filings with the Securities and Exchange Commission (SEC).

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K filed with the SEC on February 22, 2018, as supplemented by the disclosure in Part II, Item 1A. Risk Factors in this Quarterly Report on Form 10-Q.

DEFINITIONS

The following is a listing of certain abbreviations, acronyms, and other industry terminology that may be used throughout this Form 10-Q.

Measurements:
Barrel: One barrel of petroleum products that equals 42 U.S. gallons
Bcf: One billion cubic feet of natural gas
Bcf/d: One billion cubic feet of natural gas per day
British Thermal Unit (Btu): A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
Dekatherms (Dth): A unit of energy equal to one million British thermal units
Mbbls/d: One thousand barrels per day
Mdth/d: One thousand dekatherms per day
MMcf/d: One million cubic feet per day
MMdth: One million dekatherms or approximately one trillion British thermal units
MMdth/d: One million dekatherms per day
Tbtu: One trillion British thermal units
Consolidated Entities:
Cardinal: Cardinal Gas Services, L.L.C.
Constitution: Constitution Pipeline Company, LLC
Gulfstar One: Gulfstar One LLC
Northwest Pipeline: Northwest Pipeline LLC
Transco: Transcontinental Gas Pipe Line Company, LLC
WPZ: Williams Partners L.P. Effective August 10, 2018, we completed our merger with WPZ, pursuant to which we acquired all outstanding common units of WPZ held by others and Williams continued as the surviving entity.
Partially Owned Entities: Entities in which we do not own a 100 percent ownership interest and which, as of September 30, 2018, we account for as an equity-method investment, including principally the following:
Aux Sable: Aux Sable Liquid Products LP
Caiman II: Caiman Energy II, LLC
Discovery: Discovery Producer Services LLC
Gulfstream: Gulfstream Natural Gas System, L.L.C.
Jackalope: Jackalope Gas Gathering Services, L.L.C.
Laurel Mountain: Laurel Mountain Midstream, LLC
OPPL: Overland Pass Pipeline Company LLC
RMM: Rocky Mountain Midstream Holdings LLC
UEOM: Utica East Ohio Midstream LLC

Government and Regulatory:
EPA: Environmental Protection Agency
FERC: Federal Energy Regulatory Commission
SEC: Securities and Exchange Commission
Other:
ETE Merger Agreement: Merger Agreement and Plan of Merger of Williams with Energy Transfer Equity, L.P and certain of its affiliates
Fractionation: The process by which a mixed stream of natural gas liquids is separated into constituent products, such as ethane, propane, and butane
GAAP: U.S. generally accepted accounting principles
IDR: Incentive distribution right
LNG: Liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures
MVC: Minimum volume commitment
NGLs: Natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels, and gasoline additives, among other applications
NGL margins: NGL revenues less any applicable Btu replacement cost, plant fuel, and third-party transportation and fractionation
RGP Splitter: Refinery grade propylene splitter
Throughput: The volume of product transported or passing through a pipeline, plant, terminal, or other facility
WPZ Merger: The August 10, 2018 merger transactions pursuant to which we acquired all outstanding common units of WPZ held by others, merged WPZ into Williams, and Williams continued as the surviving entity

PART I – FINANCIAL INFORMATION

The Williams Companies, Inc.
Consolidated Statement of Income
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions, except per-share amounts)			
Revenues:				
Service revenues	$1,371	$1,310	$4,062	$3,853
Service revenues – commodity consideration (Note 2)	121	—	316	—
Product sales	811	581	2,104	1,950
Total revenues	2,303	1,891	6,482	5,803
Costs and expenses:				
Product costs	790	504	2,039	1,620
Processing commodity expenses (Note 2)	30	—	91	—
Operating and maintenance expenses	389	403	1,134	1,166
Depreciation and amortization expenses	425	433	1,290	1,308
Selling, general, and administrative expenses	174	138	436	452
Gain on sale of Geismar Interest (Note 4)	—	(1,095)	—	(1,095)
Impairment of certain assets (Note 12)	—	1,210	66	1,236
Other (income) expense – net	(6)	24	24	34
Total costs and expenses	1,802	1,617	5,080	4,721
Operating income (loss)	501	274	1,402	1,082
Equity earnings (losses)	105	115	279	347
Other investing income (loss) – net (Note 5)	2	4	74	278
Interest incurred	(286)	(275)	(856)	(842)
Interest capitalized	16	8	38	24
Other income (expense) – net	52	23	99	124
Income (loss) before income taxes	390	149	1,036	1,013
Provision (benefit) for income taxes	190	24	297	126
Net income (loss)	200	125	739	887
Less: Net income (loss) attributable to noncontrolling interests	71	92	323	400
Net income (loss) attributable to The Williams Companies, Inc.	129	33	416	487
Preferred stock dividends (Note 11)	—	—	—	—
Net income (loss) available to common stockholders	$129	$33	$416	$487
Amounts attributable to The Williams Companies, Inc.:				
Basic earnings (loss) per common share:				
Net income (loss)	$.13	$.04	$.47	$.59
Weighted-average shares (thousands)	1,023,587	826,779	893,706	825,925
Diluted earnings (loss) per common share:				
Net income (loss)	$.13	$.04	$.46	$.59
Weighted-average shares (thousands)	1,026,504	829,368	896,322	828,150
Cash dividends declared per common share	$.34	$.30	$1.02	$.90

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Statement of Comprehensive Income
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Net income (loss)	$200	$125	$739	$887
Other comprehensive income (loss):				
Cash flow hedging activities:				
Net unrealized gain (loss) from derivative instruments, net of taxes of $3 and $6 in 2018, and $2 and $1 in 2017	(5)	(9)	(19)	(5)
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of ($2) and ($3) in 2018, and $1 and $1 in 2017	7	2	10	—
Pension and other postretirement benefits:				
Amortization of prior service cost (credit) included in net periodic benefit cost (credit), net of taxes of $1 and $2 in 2017	—	—	—	(2)
Net actuarial gain (loss) arising during the year, net of taxes of ($0) and ($1) in 2018	—	—	4	—
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit), net of taxes of ($3) and ($5) in 2018, and ($2) and ($7) in 2017	4	4	14	13
Other comprehensive income (loss)	6	(3)	9	6
Comprehensive income (loss)	206	122	748	893
Less: Comprehensive income (loss) attributable to noncontrolling interests	72	89	321	398
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$134	$33	$427	$495

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

	September 30, 2018	December 31, 2017
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$42	$ 899
Trade accounts and other receivables (net of allowance of $9 at September 30, 2018 and $9 at December 31, 2017)	883	976
Inventories	153	113
Assets held for sale (Note 4)	664	7
Other current assets and deferred charges	242	184
Total current assets	1,984	2,179
Investments	7,427	6,552
Property, plant, and equipment	39,953	39,513
Accumulated depreciation and amortization	(11,279)	(11,302)
Property, plant, and equipment – net	28,674	28,211
Intangible assets – net of accumulated amortization	8,324	8,791
Regulatory assets, deferred charges, and other	744	619
Total assets	$47,153	$ 46,352
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$739	$ 978
Liabilities held for sale (Note 4)	49	—
Accrued liabilities	1,117	1,167
Commercial paper	823	—
Long-term debt due within one year	33	501
Total current liabilities	2,761	2,646
Long-term debt	21,409	20,434
Deferred income tax liabilities	1,648	3,147
Regulatory liabilities, deferred income, and other	4,376	3,950
Contingent liabilities (Note 13)		
Equity:		
Stockholders' equity:		
Preferred stock (Note 11)	35	—
Common stock ($1 par value; 1,470 million shares authorized at September 30, 2018 and 960 million shares authorized at December 31, 2017; 1,245 million shares issued at September 30, 2018 and 861 million shares issued at December 31, 2017)	1,245	861
Capital in excess of par value	24,680	18,508
Retained deficit	(9,018)	(8,434)
Accumulated other comprehensive income (loss)	(291)	(238)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	15,610	9,656
Noncontrolling interests in consolidated subsidiaries	1,349	6,519
Total equity	16,959	16,175
Total liabilities and equity	$47,153	$ 46,352

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Changes in Equity
(Unaudited)

	The Williams Companies, Inc., Stockholders								
	Preferred Stock	Common Stock	Capital in Excess of Par Value	Retained Deficit	AOCI*	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interests	Total Equity
	(Millions)								
Balance – December 31, 2017	$—	$ 861	$ 18,508	$ (8,434)	$ (238)	$ (1,041)	$ 9,656	$ 6,519	$ 16,175
Adoption of ASC 606 (Note 1)	—	—	—	(84)	—	—	(84)	(37)	(121)
Adoption of ASU 2018-02 (Note 1)	—	—	—	61	(61)	—	—	—	—
Net income (loss)	—	—	—	416	—	—	416	323	739
Other comprehensive income (loss)	—	—	—	—	11	—	11	(2)	9
WPZ Merger (Note 1)	—	382	6,112	—	(3)	—	6,491	(4,629)	1,862
Issuance of preferred stock (Note 11)	35	—	—	—	—	—	35	—	35
Cash dividends – common stock	—	—	—	(974)	—	—	(974)	—	(974)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(598)	(598)
Stock-based compensation and related common stock issuances	—	1	48	—	—	—	49	—	49
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	—	46	46
Changes in ownership of consolidated subsidiaries, net	—	—	14	—	—	—	14	(18)	(4)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	13	13
Deconsolidation of subsidiary (Note 3)	—	—	—	—	—	—	—	(267)	(267)
Other	—	1	(2)	(3)	—	—	(4)	(1)	(5)
Net increase (decrease) in equity	35	384	6,172	(584)	(53)	—	5,954	(5,170)	784
Balance – September 30, 2018	$35	$ 1,245	$ 24,680	$ (9,018)	$ (291)	$ (1,041)	$ 15,610	$ 1,349	$ 16,959

* Accumulated Other Comprehensive Income (Loss)
See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2018	2017
	(Millions)	
OPERATING ACTIVITIES:		
Net income (loss)	$739	$887
Adjustments to reconcile to net cash provided (used) by operating activities:		
Depreciation and amortization	1,290	1,308
Provision (benefit) for deferred income taxes	351	99
Equity (earnings) losses	(279)	(347)
Distributions from unconsolidated affiliates	507	602
Net (gain) loss on disposition of equity-method investments	—	(269)
Gain on sale of Geismar Interest (Note 4)	—	(1,095)
Impairment of and net (gain) loss on sale of assets	64	1,225
Amortization of stock-based awards	43	61
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	75	118
Inventories	(39)	(23)
Other current assets and deferred charges	(44)	(11)
Accounts payable	(76)	47
Accrued liabilities	(62)	(161)
Other, including changes in noncurrent assets and liabilities	(238)	(210)
Net cash provided (used) by operating activities	2,331	2,231
FINANCING ACTIVITIES:		
Proceeds from (payments of) commercial paper – net	821	(93)
Proceeds from long-term debt	3,745	3,013
Payments of long-term debt	(3,201)	(5,475)
Proceeds from issuance of common stock	15	2,130
Common dividends paid	(974)	(744)
Dividends and distributions paid to noncontrolling interests	(552)	(636)
Contributions from noncontrolling interests	13	15
Payments for debt issuance costs	(26)	(14)
Other – net	(46)	(87)
Net cash provided (used) by financing activities	(205)	(1,891)
INVESTING ACTIVITIES:		
Property, plant, and equipment:		
Capital expenditures (1)	(2,659)	(1,700)
Dispositions – net	(2)	(27)
Contributions in aid of construction	395	253
Proceeds from sale of businesses, net of cash divested	—	2,056
Proceeds from dispositions of equity-method investments	—	200
Purchases of and contributions to equity-method investments	(803)	(103)
Other – net	86	(17)
Net cash provided (used) by investing activities	(2,983)	662
Increase (decrease) in cash and cash equivalents	(857)	1,002

Cash and cash equivalents at beginning of year	899	170
Cash and cash equivalents at end of period	$42	$1,172

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(1) Increases to property, plant, and equipment	$(2,482)	$(1,826)
Changes in related accounts payable and accrued liabilities	(177)	126
Capital expenditures	$(2,659)	$(1,700)

See accompanying notes.

The Williams Companies, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1 – General, Description of Business, and Basis of Presentation

General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto for the year ended December 31, 2017, in Exhibit 99.1 of our Form 8-K dated May 3, 2018. The accompanying unaudited financial statements include all normal recurring adjustments and others that, in the opinion of management, are necessary to present fairly our interim financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Unless the context clearly indicates otherwise, references in this report to “Williams,” “we,” “our,” “us,” or like terms refer to The Williams Companies, Inc. and its subsidiaries. Unless the context clearly indicates otherwise, references to “Williams,” “we,” “our,” and “us” include the operations in which we own interests accounted for as equity-method investments that are not consolidated in our financial statements. When we refer to our equity investees by name, we are referring exclusively to their businesses and operations.

WPZ Merger

On August 10, 2018, we completed our merger with Williams Partners L.P. (WPZ), pursuant to which we acquired all of the approximately 256 million publicly held outstanding common units of WPZ in exchange for 382 million shares of our common stock (WPZ Merger). Williams continued as the surviving entity. The WPZ Merger was accounted for as a non-cash equity transaction resulting in increases to Common stock of $382 million, Capital in excess of par value of $6.112 billion, and Regulatory assets, deferred charges, and other of $33 million and decreases to Accumulated other comprehensive income (loss) of $3 million, Noncontrolling interests in consolidated subsidiaries of $4.629 billion, and Deferred income tax liabilities of $1.829 billion in the Consolidated Balance Sheet. Prior to the completion of the WPZ Merger and pursuant to its distribution reinvestment program, WPZ had issued 1,230,657 common units to the public in 2018 associated with reinvested distributions of $46 million.

Financial Repositioning

In January 2017, we entered into agreements with WPZ, wherein we permanently waived the general partner’s incentive distribution rights and converted our 2 percent general partner interest in WPZ to a noneconomic interest in exchange for 289 million newly issued WPZ common units. Pursuant to this agreement, we also purchased approximately 277 thousand WPZ common units for $10 million. Additionally, we purchased approximately 59 million common units of WPZ at a price of $36.08586 per unit in a private placement transaction, funded with proceeds from our equity offering. According to the terms of this agreement, concurrent with WPZ’s quarterly distributions in February 2017 and May 2017, we paid additional consideration totaling $56 million to WPZ for these units.

Description of Business

We are a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. Our operations are located principally in the United States. Prior to the WPZ Merger, we had one reportable segment, Williams Partners. Beginning in the third-quarter 2018, consistent with the manner in which our chief operating decision maker evaluates performance and allocates resources, our operations are now presented within the following reportable segments: Northeast G&P, Atlantic-Gulf, and West. Prior period segment disclosures have been recast for the new segment presentation.

Notes (Continued)

Northeast G&P is comprised of our midstream gathering and processing businesses in the Marcellus Shale region primarily in Pennsylvania, New York, and West Virginia and the Utica Shale region of eastern Ohio, as well as a 66 percent interest in Cardinal Gas Services, L.L.C. (Cardinal) (a consolidated entity), a 62 percent equity-method investment in Utica East Ohio Midstream, LLC, a 69 percent equity-method investment in Laurel Mountain Midstream, LLC, a 58 percent equity-method investment in Caiman Energy II, LLC, and Appalachia Midstream Services, LLC, which owns equity-method investments with an approximate average 66 percent interest in multiple gathering systems in the Marcellus Shale (Appalachia Midstream Investments).

Atlantic-Gulf is comprised of our interstate natural gas pipeline, Transcontinental Gas Pipe Line Company, LLC (Transco), and significant natural gas gathering and processing and crude oil production handling and transportation assets in the Gulf Coast region, including a 51 percent interest in Gulfstar One LLC (Gulfstar One) (a consolidated entity), which is a proprietary floating production system, and various petrochemical and feedstock pipelines in the Gulf Coast region, as well as a 50 percent equity-method investment in Gulfstream Natural Gas System, L.L.C., a 41 percent interest in Constitution Pipeline Company, LLC (Constitution) (a consolidated entity), which is developing a pipeline project (see Note 3 – Variable Interest Entities), and a 60 percent equity-method investment in Discovery Producer Services LLC.

West is comprised of our interstate natural gas pipeline, Northwest Pipeline LLC (Northwest Pipeline), and our gathering, processing, and treating operations in New Mexico, Colorado, and Wyoming, as well as the Barnett Shale region of north-central Texas, the Eagle Ford Shale region of south Texas, the Haynesville Shale region of northwest Louisiana, and the Mid-Continent region which includes the Anadarko, Arkoma, Delaware, and Permian basins. This segment also includes our natural gas liquid (NGL) and natural gas marketing business, storage facilities, an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, and a 50 percent equity-method investment in Overland Pass Pipeline, LLC, a 50 percent interest in Jackalope Gas Gathering Services, L.L.C. (Jackalope) (an equity-method investment following deconsolidation as of June 30, 2018), a 43 percent equity-method investment in Rocky Mountain Midstream Holdings LLC (RMM), and our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 5 – Investing Activities).

All remaining business activities, including our former Williams Olefins, L.L.C., a wholly owned subsidiary which owned our 88.5 percent undivided interest in the Geismar, Louisiana, olefins plant (Geismar Interest) (see Note 4 – Divestitures and Assets Held for Sale), as well as corporate activities, are included in Other.

Basis of Presentation

Significant risks and uncertainties

We may monetize assets that are not core to our strategy which could result in impairments of certain equity-method investments, property, plant, and equipment, and intangible assets. Such impairments could potentially be caused by indications of fair value implied through the monetization process or, in the case of asset dispositions that are part of a broader asset group, the impact of the loss of future estimated cash flows.

Proposition 112

On November 6, 2018, citizens of Colorado will vote on Proposition 112, a ballot measure that could significantly increase setback distances from occupied structures or other vulnerable areas, as defined or designated, for any new oil and gas development in the state, critically restricting or banning such activities. If the measure is approved, it could still be subject to modification or amendment by the Colorado legislature. An unfavorable outcome could adversely impact the operations, and ultimately the value, of our businesses and investments in Colorado, notably our recent investment in RMM (see Note 5 – Investing Activities).

FERC Income Tax Policy Revision

On March 15, 2018, the Federal Energy Regulatory Commission (FERC) issued a revised policy statement (the March 15 Statement) regarding the recovery of income tax costs in rates of natural gas pipelines. The FERC found that an impermissible double recovery results from granting a Master Limited Partnership (MLP) pipeline

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Notes (Continued)

both an income tax allowance and a return on equity pursuant to the discounted cash flow methodology. As a result, the FERC will no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. The FERC further stated it will address the application of this policy to non-MLP partnership forms as those issues arise in subsequent proceedings. One of the benefits of the recent WPZ Merger is to allow our FERC-regulated pipelines to continue to recover an income tax allowance in their cost of service rates.

On July 18, 2018, the FERC issued an order dismissing the requests for rehearing and clarification of the revised policy statement. In addition, the FERC provided guidance that an MLP pipeline (or other pass-through entity) no longer recovering an income tax allowance pursuant to the revised policy may eliminate previously accumulated deferred income taxes (ADIT) from its cost of service instead of flowing these ADIT balances to ratepayers. This guidance, if implemented, would significantly mitigate the impact of the March 15 Statement. However, the FERC stated that the revised policy statement and such guidance do not establish a binding rule but are instead expressions of general policy intent designed to provide guidance by notifying entities of the course of action the FERC intends to follow in future adjudications. To the extent the FERC addresses these issues in future proceedings, it will consider any arguments regarding not only the application of the revised policy to the facts of the case, but also any arguments regarding the underlying validity of the policy itself. The FERC’s guidance on ADIT likely will be challenged by customers and state commissions, which would result in a long period of revenue uncertainty for pipelines eliminating ADIT from their cost of service. The WPZ Merger has the additional benefit of eliminating this uncertainty.

On March 15, 2018, the FERC also issued a Notice of Proposed Rulemaking proposing a filing process that will allow it to determine which natural gas pipelines may be collecting unjust and unreasonable rates in light of the recent reduction in the corporate income tax rate in the Tax Cuts and Jobs Act (Tax Reform) and the revised policy statement. On July 18, 2018, the FERC issued a Final Rule, retaining the filing requirement and reaffirming the options that pipelines have to either reflect the reduced tax rate or explain why no rate change is necessary. The FERC also clarified that a natural gas company organized as a pass-through entity and all of whose income or losses are consolidated on the federal income tax return of its corporate parent is considered to be subject to the federal corporate income tax and is thus eligible for a tax allowance. We believe this Final Rule and the previously discussed WPZ Merger allow for the continued recovery of income tax allowances in Transco’s and Northwest Pipeline’s rates. Further, Transco’s August 31, 2018 general rate case filing reflects a tax allowance based on this clarification, and the FERC’s September 28, 2018 order in the rate case proceeding finds that Transco is exempt from the Final Rule’s Form 501-G filing requirement. In addition, on October 19, 2018, Northwest Pipeline filed a petition requesting that the FERC waive its Form 501-G filing requirement under this Final Rule because the reduction in the corporate income tax in Tax Reform is already addressed in its settlement.

On March 15, 2018, the FERC also issued a Notice of Inquiry seeking comments on the additional impacts of Tax Reform on jurisdictional rates, particularly whether, and if so how, the FERC should address changes relating to ADIT amounts after the corporate income tax rate reduction and bonus depreciation rules, as well as whether other features of Tax Reform require FERC action. We are evaluating the impact of these developments on our interstate natural gas pipelines and currently expect any associated impacts would be prospective and determined through subsequent rate proceedings. We also continue to monitor developments that may impact our regulatory liabilities resulting from Tax Reform. It is reasonably possible that future tariff-based rates collected by our interstate natural gas pipelines may be adversely impacted.

Accounting standards issued and adopted

During the first quarter of 2018, we early adopted Accounting Standards Update (ASU) 2018-02 “Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income” (ASU 2018-02). As a result of Tax Reform lowering the federal income tax rate, the tax effects of items within accumulated other comprehensive income may not reflect the appropriate tax rate. ASU 2018-02 allows for the reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from Tax Reform. The adoption of ASU 2018-02 resulted in the reclassification of $61 million from Accumulated other comprehensive income (loss) to Retained deficit on our Consolidated Balance Sheet.

Notes (Continued)

Effective January 1, 2018, we adopted ASU 2017-12 “Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities” (ASU 2017-12). ASU 2017-12 applies to entities that elect hedge accounting in accordance with Accounting Standards Codification (ASC) 815. The ASU affects both the designation and measurement guidance for hedging relationships and the presentation of hedging results. ASU 2017-12 was applied using a modified retrospective approach for cash flow and net investment hedges existing at the date of adoption and prospectively for the presentation and disclosure guidance. The adoption of ASU 2017-12 did not have a significant impact on our consolidated financial statements.

Effective January 1, 2018, we adopted ASU 2017-07 “Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost” (ASU 2017-07). ASU 2017-07 requires employers to report the service cost component of net benefit cost in the same line item or items as other compensation costs arising from employee services. The other components of net benefit cost must be presented in the income statement separately from the service cost component and outside Operating income (loss). Only the service cost component is now eligible for capitalization when applicable. The presentation aspect of ASU 2017-07 must be applied retrospectively and the capitalization requirement prospectively. In accordance with this adoption, we have conformed the prior year presentation, which resulted in increases of $3 million and $9 million to Operating and maintenance expenses with corresponding decreases to Operating income (loss) and increases of $3 million and $9 million to Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Income for the three- and nine-month periods ended September 30, 2017, respectively.

Effective January 1, 2018, we adopted ASU 2016-15 “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments” (ASU 2016-15). Among other things, ASU 2016-15 permits an accounting policy election to classify distributions received from equity-method investees using either the cumulative earnings approach or the nature of distribution approach. We have elected to apply the nature of distribution approach and have retrospectively conformed the prior year presentation within the Consolidated Statement of Cash Flows in accordance with ASU 2016-15. For the period ended September 30, 2017, amounts previously presented as Distributions from unconsolidated affiliates in excess of cumulative earnings within Investing Activities are now presented as part of Distributions from unconsolidated affiliates within Operating Activities, resulting in an increase to Net cash provided (used) by operating activities of $394 million with a corresponding reduction in Net cash provided (used) by investing activities.

In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09 establishing ASC Topic 606, “Revenue from Contracts with Customers” (ASC 606). ASC 606 establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to be entitled to receive in exchange for those goods or services and requires significantly enhanced revenue disclosures. In August 2015, the FASB issued ASU 2015-14 “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date” (ASU 2015-14). Per ASU 2015-14, the standard became effective for interim and annual reporting periods beginning after December 15, 2017.

We adopted the provisions of ASC 606 effective January 1, 2018, utilizing the modified retrospective transition method for all contracts with customers, which included applying the provisions of ASC 606 beginning January 1, 2018, to all contracts not completed as of that date with the cumulative effect of applying the standard for periods prior to January 1, 2018, as an adjustment to Total equity, net of tax, upon adoption. As a result of our adoption, the cumulative impact to our Total equity, net of tax, at January 1, 2018, was a decrease of $121 million in the Consolidated Balance Sheet.

For each revenue contract type, we conducted a formal contract review process to evaluate the impact of ASC 606. The adjustment to Total equity upon adoption of ASC 606 is primarily comprised of the impact to the timing of recognition of deferred revenue (contract liabilities) associated with certain contracts which underwent modifications in periods prior to January 1, 2018. Under the provisions of ASC 606, when a contract modification does not increase both the scope and price of the contract, and the remaining goods and services are distinct from the goods and services transferred prior to the modification, the modification is treated as a termination of the existing contract and the creation of a new contract. ASC 606 requires that the transaction price, including any remaining contract liabilities from the old contract, be allocated to the performance obligations over the term of the new contract. The contract modification adjustments are partially offset by the impact of changes to the timing of recognizing revenue which is subject to the constraint on estimates of variable consideration of certain contracts. The constraint of variable consideration will result in the acceleration of revenue recognition and corresponding de-recognition of contract liabilities for certain contracts (as compared to the previous revenue recognition model) as a result of our assessment that it is probable such recognition would not result in a significant revenue reversal in the future. Additionally, under ASC 606, our revenues will increase in situations where we receive noncash consideration, which exists primarily in certain of our gas processing contracts where we receive commodities as full or partial consideration for services provided. This increase in revenues will be offset by a similar increase in costs and expenses when the commodities received are subsequently sold. Financial systems and internal controls necessary for adoption were implemented effective January 1, 2018. (See Note 2 – Revenue Recognition.)

Accounting standards issued but not yet adopted

In June 2016, the FASB issued ASU 2016-13 “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments” (ASU 2016-13). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments. For trade and other receivables, held-to-maturity debt securities, loans, and other instruments, entities will be required to use a new forward-looking “expected loss” model that generally will result in the earlier recognition of allowances for losses. The guidance also requires increased disclosures. ASU 2016-13 is effective for interim and annual periods beginning after December 15, 2019. Early adoption is permitted. The standard requires varying transition methods for the different categories of amendments. Although we do not expect ASU 2016-13 to have a significant impact, it could impact our trade receivables as the related allowance for credit losses will be recognized earlier under the expected loss model.

In February 2016, the FASB issued ASU 2016-02 “Leases (Topic 842)” (ASU 2016-02). ASU 2016-02 establishes a comprehensive new lease accounting model. ASU 2016-02 modifies the definition of a lease, requires a dual approach to lease classification similar to current lease accounting, and causes lessees to recognize operating leases on the balance sheet as a lease liability measured as the present value of the future lease payments with a corresponding right-of-use asset, with an exception for leases with a term of one year or less. Additional disclosures will also be required regarding the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued ASU 2018-01 “Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842” (ASU 2018-01). Per ASU 2018-01, land easements and rights-of-way are required to be assessed under ASU 2016-02 to determine whether the arrangements are or contain a lease. ASU 2018-01 permits an entity to elect a transition practical expedient to not apply ASU 2016-02 to land easements that exist or expired before the effective date of ASU 2016-02 and that were not previously assessed under the previous lease guidance in ASC Topic 840 “Leases.”

In July 2018, the FASB issued ASU 2018-11 “Leases (Topic 842): Targeted Improvements” (ASU 2018-11). Prior to ASU 2018-11, a modified retrospective transition was required for financing or operating leases existing at or entered into after the beginning of the earliest comparative period presented in the financial statements. ASU 2018-11 allows entities an additional transition method to the existing requirements whereby an entity could adopt the provisions of ASU 2016-02 by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption without adjustment to the financial statements for periods prior to adoption. ASU 2018-11 also allows a practical expedient that permits lessors to not separate non-lease components from the associated lease component if certain conditions are present. ASU 2016-02 is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. We will adopt ASU 2016-02 effective January 1, 2019.

We are in the process of finalizing our review of contracts to identify leases based on the modified definition of a lease and identifying changes to our internal controls to support management in the accounting for and disclosure of leasing activities upon adoption of ASU 2016-02. We implemented a financial lease accounting system to assist management in the accounting for leases upon adoption. While we are still in the process of completing our implementation evaluation of ASU 2016-02, we currently believe the most significant changes to our financial statements relate to the recognition of a lease liability and offsetting right-of-use asset in our Consolidated Balance Sheet for operating leases. We are also evaluating ASU 2016-02’s available practical expedients on adoption, which we generally expect to elect.

Notes (Continued)

Note 2 – Revenue Recognition

Customers in our gas pipeline businesses are comprised of public utilities, municipalities, gas marketers and producers, intrastate pipelines, direct industrial users, and electrical generators. Customers in our midstream businesses are comprised of oil and natural gas producer counterparties. Customers for our product sales are comprised of public utilities, gas marketers, and direct industrial users.

A performance obligation is a promise in a contract to transfer a distinct good or service (or integrated package of goods or services) to the customer. A contract's transaction price is allocated to each distinct performance obligation and recognized as revenue, when, or as, the performance obligation is satisfied. A performance obligation is distinct if the service is separately identifiable from other items in the integrated package of services and if a customer can benefit from it on its own or with other resources that are readily available to the customer. An integrated package of services typically represents a single performance obligation if the services are contained within the same contract or within multiple contracts entered into in contemplation with one another that are highly interdependent or highly interrelated, meaning each of the services is significantly affected by one or more of the other services in the contract. Service revenue contracts from our gas pipeline and midstream businesses contain a series of distinct services, with the majority of our contracts having a single performance obligation that is satisfied over time as the customer simultaneously receives and consumes the benefits provided by our performance. Most of our product sales contracts have a single performance obligation with revenue recognized at a point in time when the products have been sold and delivered to the customer.

Certain customers reimburse us for costs we incur associated with construction of property, plant, and equipment utilized in our operations. For our rate-regulated gas pipeline businesses that apply ASC 980. "Regulated Operations" (Topic 980), we follow FERC guidelines with respect to reimbursement of construction costs. FERC tariffs only allow for cost reimbursement and are non-negotiable in nature; thus, the construction activities do not represent an ongoing major and central operation of our gas pipeline businesses and are not within the scope of ASC 606. Accordingly, cost reimbursements are treated as a reduction to the cost of the constructed asset. For our midstream businesses, reimbursement and service contracts with customers are viewed together as providing the same commercial objective, as we have the ability to negotiate the mix of consideration between reimbursements and amounts billed over time. Accordingly, we generally recognize reimbursements of construction costs from customers on a gross basis as a contract liability separate from the associated costs included within property, plant, and equipment. The contract liability is recognized into service revenues as the underlying performance obligations are satisfied.

Service Revenues

Gas pipeline businesses

Revenues from our interstate natural gas pipeline businesses, which are included within the caption "Regulated interstate natural gas transportation and storage" in the revenue by category table below and are subject to regulation by certain state and federal authorities, including the FERC, include both firm and interruptible transportation and storage contracts. Firm transportation and storage agreements provide for a reservation charge based on the pipeline or storage capacity reserved, and a commodity charge based on the volume of natural gas delivered/stored, each at rates specified in our FERC tariffs or based on negotiated contractual rates, with contract terms that are generally long-term in nature. Most of our long-term contracts contain an evergreen provision, which allows the contracts to be extended for periods primarily up to one year in length an indefinite number of times following the specified contract term and until terminated generally by either us or the customer. Interruptible transportation and storage agreements provide for a volumetric charge based on actual commodity transportation or storage utilized in the period in which those services are provided, and the contracts are generally limited to one-month periods or less. Our performance obligations related to our interstate natural gas pipeline businesses include the following:

- Guaranteed transportation or storage under firm transportation and storage contracts—an integrated package of services typically constituting a single performance obligation, which includes standing ready to provide such services and receiving, transporting or storing (as applicable), and redelivering commodities;

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Notes (Continued)

- Interruptible transportation and storage under interruptible transportation and storage contracts—an integrated package of services typically constituting a single performance obligation, which includes receiving, transporting or storing (as applicable), and redelivering commodities upon nomination by the customer.

In situations where we consider the integrated package of services as a single performance obligation, which represents a majority of our interstate natural gas pipeline contracts with customers, we do not consider there to be multiple performance obligations because the nature of the overall promise in the contract is to stand ready (with regard to firm transportation and storage contracts), receive, transport or store, and redeliver natural gas to the customer; therefore, revenue is recognized at the completion of the integrated package of services which represents a single performance obligation.

We recognize revenues for reservation charges over the performance obligation period, which is the contract term, regardless of the volume of natural gas that is transported or stored. Revenues for commodity charges from both firm and interruptible transportation services and storage services are recognized when natural gas is delivered at the agreed upon delivery point or when natural gas is injected or withdrawn from the storage facility because they specifically relate to our efforts to provide these distinct services. Generally, reservation charges and commodity charges in our interstate natural gas pipeline businesses are recognized as revenue in the same period they are invoiced to our customers. As a result of the ratemaking process, certain amounts collected by us may be subject to refund upon the issuance of final orders by the FERC in pending rate proceedings. We record estimates of rate refund liabilities considering our and other third-party regulatory proceedings, advice of counsel, and other risks.

Midstream businesses

Revenues from our midstream businesses, which are included in the caption titled “Non-regulated gathering, processing, transportation, and storage” in the revenue by category table below, include contracts for natural gas gathering, processing, treating, compression, transportation, and other related services with contract terms that are generally long-term in nature and may extend up to the production life of the associated reservoir. Additionally, our midstream businesses generate revenues from fees charged for storing customers’ natural gas and NGLs, generally under prepaid contracted storage capacity contracts. In situations where we provide an integrated package of services combined into a single performance obligation, which represents a majority of this class of contracts with customers, we do not consider there to be multiple performance obligations because the nature of the overall promise in the contract is to provide gathering, processing, transportation, storage, and related services resulting in the delivery, or redelivery in the context of storage services, of pipeline-quality natural gas and NGLs to the customer. As such, revenue is recognized at the daily completion of the integrated package of services as the integrated package represents a single performance obligation. Additionally, certain contracts in our midstream businesses contain fixed or upfront payment terms that result in the deferral of revenues until such services have been performed or such capacity has been made available.

We also earn revenues from offshore crude oil and natural gas gathering and transportation and offshore production handling. These services represent an integrated package of services and are considered a single distinct performance obligation for which we recognize revenues as the services are provided to the customer.

We generally earn a contractually stated fee per unit for the volume of product transported, gathered, processed, or stored. The rate is generally fixed; however, certain contracts contain variable rates that are subject to change based on commodity prices, levels of throughput, or an annual adjustment based on a formulaic cost of service calculation. In addition, we have contracts with contractually stated fees that decline over the contract term, such as declines based on the passage of time periods or achievement of cumulative throughput amounts. For all of our contracts, we allocate the transaction price to each performance obligation based on the relative standalone selling price. The excess of consideration received over revenue recognized results in the deferral of those amounts until future periods based on a units of production or straight-line methodology. Certain of our gas gathering and processing agreements have minimum volume commitments (MVC). If a customer under such an agreement fails to meet its MVC for a specified period (thus not exercising all the contractual rights to gathering and processing services within the specified period, herein referred to as “breakage”), it is obligated to pay a contractually determined fee based upon the shortfall between the actual gathered or processed volumes and the MVC for the period contained in the contract. When we conclude it

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Notes (Continued)

is probable that the customer will not exercise all or a portion of its remaining rights, we recognize revenue associated with such breakage amount in proportion to the pattern of exercised rights within the respective MVC period.

Under keep-whole and percent-of-liquids processing contracts, we receive commodity consideration in the form of NGLs and take title to the NGLs at the tailgate of the plant. We recognize such commodity consideration as service revenue based on the market value of the NGLs retained at the time the processing is provided. The current market value, as opposed to the market value at the contract inception date, is used due to a combination of factors, including the fact that the volume, mix, and market price of NGL consideration to be received is unknown at the time of contract execution and is not specified in our contracts with customers. Additionally, product sales revenue (discussed below) is recognized upon the sale of the NGLs to a third party based on the sales price at the time of sale. As a result, revenue is recognized both at the time the processing service is provided in Service revenues – commodity consideration and at the time the NGLs retained as part of the processing service are sold in Product sales. The recognition of revenue related to commodity consideration has the impact of increasing the book value of NGL inventory, resulting in higher cost of goods sold at the time of sale. Given that most inventory is sold in the same period that it is generated, the impact of these transactions is expected to have little impact to operating income.

Product Sales

In the course of providing transportation services to customers of our gas pipeline businesses and gathering and processing services to customers of our midstream businesses, we may receive different quantities of natural gas from customers than the quantities delivered on behalf of those customers. The resulting imbalances are primarily settled through the purchase or sale of natural gas with each customer under terms provided for in our FERC tariffs or gathering and processing agreements, respectively. Revenue is recognized from the sale of natural gas upon settlement of imbalances.

In certain instances, we purchase NGLs, crude oil, and natural gas from our oil and natural gas producer customers. In addition, we retain NGLs as consideration in certain processing arrangements, as discussed above in the Service Revenues - Midstream businesses section. We recognize revenue from the sale of these commodities when the products have been sold and delivered. Our product sales contracts are primarily short-term contracts based on prevailing market rates at the time of the transaction.

Notes (Continued)

Revenue by Category

The following table presents our revenue disaggregated by major service line:

	Northeast Midstream	Atlantic-Gulf Midstream	West Midstream	Transco	Northwest Pipeline	Other	Intercompany Eliminations	Total
	(Millions)							
Three Months Ended September 30, 2018								
Revenues from contracts with customers:								
Service revenues:								
Non-regulated gathering, processing, transportation, and storage:								
Monetary consideration	$219	$ 139	$ 409	$—	$ —	$ 1	$ (19)	$749
Commodity consideration	5	19	97	—	—	—	—	121
Regulated interstate natural gas transportation and storage	—	—	—	457	110	—	(1)	566
Other	23	4	11	—	—	—	(4)	34
Total service revenues	247	162	517	457	110	1	(24)	1,470
Product Sales:								
NGL and natural gas	69	88	720	41	—	—	(117)	801
Other	—	—	12	—	—	—	(3)	9
Total product sales	69	88	732	41	—	—	(120)	810
Total revenues from contracts with customers	316	250	1,249	498	110	1	(144)	2,280
Other revenues (1)	6	5	3	3	—	9	(3)	23
Total revenues	$322	$ 255	$ 1,252	$501	$ 110	$ 10	$ (147)	$2,303
Nine Months Ended September 30, 2018								
Revenues from contracts with customers:								
Service revenues:								
Non-regulated gathering, processing, transportation, and storage:								
Monetary consideration	$626	$ 404	$ 1,231	$—	$ —	$ 2	$ (55)	$2,208
Commodity consideration	14	45	257	—	—	—	—	316
Regulated interstate natural gas transportation and storage	—	—	—	1,368	330	—	(2)	1,696
Other	65	12	35	1	—	—	(10)	103
Total service revenues	705	461	1,523	1,369	330	2	(67)	4,323
Product Sales:								
NGL and natural gas	242	232	1,799	96	—	—	(285)	2,084
Other	—	—	20	—	—	—	(4)	16
Total product sales	242	232	1,819	96	—	—	(289)	2,100
Total revenues from contracts with customers	947	693	3,342	1,465	330	2	(356)	6,423
Other revenues (1)	16	14	6	8	—	24	(9)	59
Total revenues	$963	$ 707	$ 3,348	$1,473	$ 330	$ 26	$ (365)	$6,482

(1)

Service revenues in our Consolidated Statement of Income include leasing revenues associated with our headquarters building and management fees that we receive for certain services we provide to operated joint ventures and other investments. The leasing revenues and the management fees do not constitute revenue from contracts with customers. Product sales in our Consolidated Statement of Income include amounts associated with our derivative contracts that are not within the scope of ASC 606.

Notes (Continued)

Contract Assets

Our contract assets primarily consist of revenue recognized under contracts containing MVC features whereby management has concluded it is probable there will be a short-fall payment at the end of the current MVC period, which typically follows the calendar year, and that a significant reversal of revenue recognized currently for the future MVC payment will not occur. As a result, our contract assets related to our future MVC payments are generally expected to be collected within the next 12 months and are included within Other current assets and deferred charges in our Consolidated Balance Sheet until such time as the MVC short-fall payments are invoiced to the customer.

The following table presents a reconciliation of our contract assets:

	Quarter-to-Date September 30, 2018	Year-to-Date September 30, 2018
	(Millions)	
Balance at beginning of period	$ 39	$ 4
Revenue recognized in excess of cash received	17	53
Minimum volume commitments invoiced	—	(1)
Balance at end of period	$ 56	$ 56

Contract Liabilities

Our contract liabilities consist of advance payments primarily from midstream business customers which include construction reimbursements, prepayments, and other billings for which future services are to be provided under the contract. These amounts are deferred until recognized in revenue when the associated performance obligation has been satisfied, which is primarily based on a units of production methodology over the remaining contractual service periods, and are classified as current or noncurrent according to when such amounts are expected to be recognized. Current and noncurrent contract liabilities are included within Accrued liabilities and Regulatory liabilities, deferred income, and other, respectively, in our Consolidated Balance Sheet.

Contracts requiring advance payments and the recognition of contract liabilities are evaluated to determine whether the advance payments provide us with a significant financing benefit. This determination is based on the combined effect of the expected length of time between when we transfer the promised good or service to the customer, when the customer pays for those goods or services, and the prevailing interest rates. We have assessed our contracts for significant financing components and determined that one group of contracts entered into in contemplation of one another for certain capital reimbursements contains a significant financing component. As a result, we recognize noncash interest expense based on the effective interest method and revenue (noncash) is recognized when the underlying asset is placed into service utilizing a units of production or straight-line methodology over the life of the corresponding customer contract.

The following table presents a reconciliation of our contract liabilities:

	Quarter-to-Date September 30, 2018	Year-to-Date September 30, 2018
	(Millions)	
Balance at beginning of period	$1,535	$ 1,596
Payments received and deferred	62	280
Deconsolidation of Jackalope interest (Note 3)	—	(52)
Recognized in revenue	(112)	(339)
Balance at end of period	$1,485	$ 1,485

Notes (Continued)

The following table presents the amount of the contract liabilities balance as of September 30, 2018, expected to be recognized as revenue in each of the next five years as performance obligations are expected to be satisfied:

	(Millions)
2018 (remainder)	$ 191
2019	257
2020	129
2021	110
2022	103
2023	100
Thereafter	595
Total	$ 1,485

Remaining Performance Obligations

The following table presents the transaction price allocated to the remaining performance obligations under certain contracts as of September 30, 2018. These primarily include long-term contracts containing MVCs associated with our midstream businesses, fixed payments associated with offshore production handling, and reservation charges on contracted capacity on our gas pipeline firm transportation contracts with customers, as well as storage capacity contracts. Amounts included in the table below for our interstate natural gas pipeline businesses reflect the rates for such services in our current FERC tariffs for the life of the related contracts; however, these rates may change based on future tariffs approved by the FERC and the amount and timing of these changes is not currently known. As a practical expedient permitted by ASC 606, this table excludes variable consideration as well as consideration in contracts that is recognized in revenue as billed. It also excludes consideration received prior to September 30, 2018, that will be recognized in future periods (see above for Contract Liabilities and the expected recognition of those amounts within revenue). As noted above, certain of our contracts contain evergreen and other renewal provisions for periods beyond the initial term of the contract. The remaining performance obligation amounts as of September 30, 2018, do not consider potential future performance obligations for which the renewal has not been exercised. The table below also does not include contracts with customers for which the underlying facilities have not received FERC authorization to be placed into service.

	(Millions)
2018 (remainder)	$ 624
2019	2,465
2020	2,274
2021	2,106
2022	1,830
2023	1,650
Thereafter	12,471
Total	$ 23,420

The table above excludes remaining performance obligations associated with the Atlantic Sunrise expansion project for which we received FERC authorization to place into service in October 2018. We anticipate annual performance obligations of approximately $420 million associated with Atlantic Sunrise over the term of the contracts.

Accounts Receivable

We do not offer extended payment terms and typically receive payment within one month. We consider receivables past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectability is assured.

Notes (Continued)

The following is a summary of our Trade accounts and other receivables as it relates to contracts with customers:

	September 30, 2018	January 1, 2018
	(Millions)	
Accounts receivable related to revenues from contracts with customers	$795	$ 958
Other accounts receivable	88	18
Total reflected in Trade accounts and other receivables	$883	$ 976

Impact of Adoption of ASC 606

The following table depicts the impact of the adoption of ASC 606 on our 2018 financial statements. The adjustment to Intangible assets – net of accumulated amortization in the table below relates to the recognition under ASC 606 of contract assets for MVC-related contracts associated with a 2014 acquisition. The recognition of these contract assets resulted in a lower purchase price allocation to intangible assets. The adoption of ASC 606 did not result in adjustments to total operating, investing, or financing cash flows.

	As Reported	Adjustments resulting from adoption of ASC 606	Balance without adoption of ASC 606
	(Millions)		
Consolidated Statement of Income			
Three Months Ended September 30, 2018			
Service revenues	$1,371	$ 5	$ 1,376
Service revenues – commodity consideration	121	(121)	—
Product sales	811	44	855
Total revenues	2,303	(72)	2,231
Product costs	790	(48)	742
Processing commodity expenses	30	(30)	—
Depreciation and amortization expenses	425	1	426
Total costs and expenses	1,802	(77)	1,725
Operating income (loss)	501	5	506
Interest incurred	(286)	4	(282)
Interest capitalized	16	(2)	14
Income (loss) before income taxes	390	7	397
Provision (benefit) for income taxes	190	1	191
Net income (loss)	200	6	206
Less: Net income (loss) attributable to noncontrolling interests	71	(1)	70
Net income (loss) attributable to The Williams Companies, Inc.	129	7	136
Basic earnings (loss) per common share	$0.13	$ 0.01	$ 0.14
Diluted earnings (loss) per common share	$0.13	$ 0.01	$ 0.14
Nine Months Ended September 30, 2018			
Service revenues	$4,062	$ 16	$ 4,078
Service revenues – commodity consideration	316	(316)	—
Product sales	2,104	86	2,190
Total revenues	6,482	(214)	6,268

Product costs	2,039	(143)	1,896
Processing commodity expenses	91	(91)	—
Operating and maintenance expenses	1,134	3	1,137
Depreciation and amortization expenses	1,290	2	1,292
Total costs and expenses	5,080	(229)	4,851

Notes (Continued)

	As Reported	Adjustments resulting from adoption of ASC 606	Balance without adoption of ASC 606
	(Millions)		
Operating income (loss)	$ 1,402	$ 15	$ 1,417
Equity earnings (losses)	279	1	280
Other investing income (loss) - net	74	(9)	65
Interest incurred	(856)	11	(845)
Interest capitalized	38	(6)	32
Income (loss) before income taxes	1,036	12	1,048
Provision (benefit) for income taxes	297	1	298
Net income (loss)	739	11	750
Net income (loss) attributable to The Williams Companies, Inc.	416	11	427
Basic earnings (loss) per common share	$ 0.47	$ 0.01	$ 0.48
Diluted earnings (loss) per common share	$ 0.46	$ 0.01	$ 0.47
Consolidated Statement of Comprehensive Income Three Months Ended September 30, 2018			
Net income (loss)	$ 200	$ 6	$ 206
Comprehensive income (loss)	206	6	212
Less: Comprehensive income (loss) attributable to noncontrolling interests	72	(1)	71
Comprehensive income (loss) attributable to The	134	7	141

Williams Companies, Inc.			
Nine Months Ended September 30, 2018			
Net income (loss)	$ 739	$ 11	$ 750
Comprehensive income (loss)	748	11	759
Comprehensive income (loss) attributable to The Williams Companies, Inc.	427	11	438
Consolidated Balance Sheet September 30, 2018			
Inventories	$ 153	$ (8)	$ 145
Other current assets and deferred charges	242	(53)	189
Total current assets	1,984	(61)	1,923
Investments	7,427	(1)	7,426
Property, plant, and equipment	39,953	(6)	39,947
Property, plant, and equipment – net	28,674	(6)	28,668
Intangible assets – net of accumulated amortization	8,324	63	8,387
Regulatory assets, deferred charges, and other	744	(4)	740
Total assets	47,153	(9)	47,144
Deferred income tax liabilities	1,648	27	1,675
Regulatory liabilities, deferred income, and other	4,376	(159)	4,217
Retained deficit	(9,018)	95	(8,923)
Total stockholders' equity	15,610	95	15,705
Noncontrolling interests in consolidated subsidiaries	$ 1,349	$ 28	$ 1,377
Total equity	16,959	123	17,082
Total liabilities and equity	47,153	(9)	47,144

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Notes (Continued)

	As Reported	Adjustments resulting from adoption of ASC 606	Balance without adoption of ASC 606
	(Millions)		
Consolidated Statement of Changes in Equity			
September 30, 2018			
Adoption of ASC 606	$(121)	$ 121	$ —
Net income (loss)	739	11	750
Deconsolidation of subsidiary	(267)	(9)	(276)
Net increase (decrease) in equity	784	123	907
Balance at September 30, 2018	16,959	123	17,082

Note 3 – Variable Interest Entities

Consolidated VIEs

As of September 30, 2018, we consolidate the following variable interest entities (VIEs):

Gulfstar One

We own a 51 percent interest in Gulfstar One, a subsidiary that, due to certain risk-sharing provisions in its customer contracts, is a VIE. Gulfstar One includes a proprietary floating-production system, Gulfstar FPS, and associated pipelines which provide production handling and gathering services in the eastern deepwater Gulf of Mexico. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Gulfstar One's economic performance.

Constitution

We own a 41 percent interest in Constitution, a subsidiary that, due to shipper fixed-payment commitments under its long-term firm transportation contracts, is a VIE. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Constitution's economic performance. We, as operator of Constitution, are responsible for constructing the proposed pipeline connecting its gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and the Tennessee Gas Pipeline systems. The total remaining cost of the project is estimated to be approximately $740 million, which would be funded with capital contributions from us and the other equity partners on a proportional basis.

In December 2014, Constitution received approval from the FERC to construct and operate its proposed pipeline. However, in April 2016, the New York State Department of Environmental Conservation (NYSDEC) denied the necessary water quality certification under Section 401 of the Clean Water Act for the New York portion of the pipeline. In May 2016, Constitution appealed the NYSDEC's denial of the Section 401 certification to the United States Court of Appeals for the Second Circuit and in August 2017, the court issued a decision denying in part and dismissing in part Constitution's appeal. The court expressly declined to rule on Constitution's argument that the delay in the NYSDEC's decision on Constitution's Section 401 application constitutes a waiver of the certification requirement. The court determined that it lacked jurisdiction to address that contention and found that jurisdiction over the waiver issue lies exclusively with the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). As to the denial itself, the court determined that NYSDEC's action was not arbitrary or capricious. Constitution filed a petition for rehearing with the Second Circuit Court of Appeals, but in October 2017 the court denied our petition.

In October 2017, we filed a petition for declaratory order requesting the FERC to find that, by operation of law, the Section 401 certification requirement for the New York State portion of Constitution's pipeline project was waived due to the failure by the NYSDEC to act on Constitution's Section 401 application within a reasonable period of time as required by the express terms of such statute. In January 2018, the FERC denied our petition, finding that Section 401 provides that a state waives certification only when it does not act on an application within one year from the date of the application. We filed a request for rehearing of the FERC's decision, but in July 2018 the FERC denied our request.

Notes (Continued)

The project's sponsors remain committed to the project, and in September 2018 we filed a petition with the D.C. Circuit for review of the FERC's decision. An unfavorable resolution could result in the impairment of a significant portion of the capitalized project costs, which total $377 million on a consolidated basis at September 30, 2018, and are included within Property, plant, and equipment in the Consolidated Balance Sheet. Beginning in April 2016, we discontinued capitalization of development costs related to this project. It is also possible that we could incur certain supplier-related costs in the event of a continued prolonged delay or termination of the project.

Cardinal

We own a 66 percent interest in Cardinal, a subsidiary that provides gathering services for the Utica Shale region and is a VIE due to certain risks shared with customers. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Cardinal's economic performance. Future expansion activity is expected to be funded with capital contributions from us and the other equity partner on a proportional basis.

The following table presents amounts included in our Consolidated Balance Sheet that are for the use or obligation of our consolidated VIEs:

	September 30, 2018	December 31, 2017 (1)	Classification
	(Millions)		
Assets (liabilities):			
Cash and cash equivalents	$ 32	$ 881	Cash and cash equivalents
Trade accounts and other receivables – net	57	972	Trade accounts and other receivables
Inventories	—	113	Inventories
Other current assets	1	176	Other current assets and deferred charges
Investments	—	6,552	Investments
Property, plant, and equipment – net	2,398	27,912	Property, plant, and equipment – net
Intangible assets – net	1,189	8,790	Intangible assets – net of accumulated amortization
Regulatory assets, deferred charges, and other noncurrent assets	—	507	Regulatory assets, deferred charges, and other
Accounts payable	(16)	(957)	Accounts payable
Accrued liabilities including current asset retirement obligations	(98)	(857)	Accrued liabilities
Long-term debt due within one year	—	(501)	Long-term debt due within one year
Long-term debt	—	(15,996)	Long-term debt
Deferred income tax liabilities	—	(16)	Deferred income tax liabilities
Noncurrent asset retirement obligations	(104)	(944)	Regulatory liabilities, deferred income, and other
Regulatory liabilities, deferred income, and other noncurrent liabilities	(189)	(2,809)	Regulatory liabilities, deferred income, and other

(1) Includes WPZ, which was a consolidated VIE at December 31, 2017 (see Note 1 – General, Description of Business, and Basis of Presentation).

Nonconsolidated VIEs

Jackalope

We own a 50 percent interest in Jackalope, which provides gathering and processing services for the Powder River basin and is a VIE due to certain risks shared with customers. Prior to the second quarter of 2018 we were the primary beneficiary of Jackalope. During the second quarter of 2018, the scope of Jackalope’s planned future activities changed,

Notes (Continued)

resulting in a VIE reconsideration event. Upon evaluation, we determined that we are no longer the primary beneficiary, most notably due to changes in the activities that most significantly impact Jackalope's economic performance and our determination that we do not control the power to direct such activities. These activities are primarily related to the capital decision making process. As a result, we deconsolidated Jackalope on June 30, 2018 and now account for our interest using the equity method of accounting as we exert significant influence over the financial and operational policies of Jackalope (see Note 5 – Investing Activities). At September 30, 2018, the carrying value of our investment in Jackalope was $316 million. Our maximum exposure to loss is limited to the carrying value of our investment. Jackalope is undertaking an expansion project that is estimated to cost up to approximately $400 million, which will be funded on a proportional basis.

Note 4 – Divestitures and Assets Held for Sale

Divestment of Four Corners Assets

On October 1, 2018, we completed the sale of our natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado for total consideration of $1.125 billion, subject to customary working capital adjustments, of which a $113 million deposit was received in the third quarter. At September 30, 2018, these assets were designated as held for sale within the West segment. As a result of this sale, we expect to record a gain of approximately $0.6 billion in the fourth quarter of 2018.

The following table presents the carrying amounts of the major classes of the Four Corners area assets and liabilities, which are presented within Assets held for sale and Liabilities held for sale in the Consolidated Balance Sheet:

	Carrying Amount September 30, 2018 (Millions)
Assets:	
Current assets	$ 23
Property, plant, and equipment – net	539
Other noncurrent assets	12
	$ 574
Liabilities:	
Current liabilities	$ 22
Other noncurrent liabilities	23
	$ 45

The following table presents the results of operations for the Four Corners area:

	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
	(Millions)			
Income (loss) before income taxes of Four Corners area	$25	$ 14	$ 52	$ 31
Income (loss) before income taxes of Four Corners area attributable to The Williams Companies, Inc.	23	10	43	23

Other Assets Held for Sale

Certain assets and operations from our former petchem services are designated as held for sale within the Atlantic-Gulf and Other segments as of September 30, 2018. Included as part of the disposal group and presented within Assets held for sale and Liabilities held for sale in the Consolidated Balance Sheet, are Current assets and Property, plant, and equipment - net, of approximately $2 million and $84 million, respectively, and Current liabilities and Noncurrent

Notes (Continued)

liabilities of approximately $1 million and $3 million, respectively. Assets held for sale also includes certain other insignificant assets unrelated to these disposal groups.

Divestment of Geismar Interest

In July 2017, we completed the sale of Williams Olefins, L.L.C., a wholly owned subsidiary which owned our Geismar Interest for total consideration of $2.084 billion in cash. We received a final working capital adjustment of $12 million in October 2017. Upon closing of the sale, we entered into a long-term supply and transportation agreement with the purchaser to provide feedstock to the plant via our Bayou Ethane pipeline system. As a result of this sale, we recorded a gain of $1.095 billion in the third quarter of 2017 in our Other segment. Following this sale, the cash proceeds were used to repay our $850 million term loan. Proceeds were also used to fund a portion of the capital and investment expenditures that were a part of our growth portfolio.

The following table presents the results of operations for the Geismar Interest, excluding the gain noted above:

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(Millions)			
Income (loss) before income taxes of the Geismar Interest	$—	$ 1	$ —	$ 26
Income (loss) before income taxes of the Geismar Interest attributable to The Williams Companies, Inc.	—	1	—	19

Note 5 – Investing Activities

RMM Equity-Method Investment

During the third quarter of 2018, our joint venture, RMM, purchased a natural gas and oil gathering and natural gas processing business in Colorado's Denver-Julesburg basin. Our initial economic ownership was 40 percent, which is expected to increase to 50 percent as we provide additional capital contributions. At September 30, 2018, our carrying value was $569 million reflecting our 43 percent economic ownership. We are committed to fund up to an additional $177 million to reach 50 percent economic ownership, to the extent RMM needs funding for capital expenditures. We account for this investment under the equity method of accounting.

Jackalope Deconsolidation

During the second quarter of 2018, we deconsolidated our interest in Jackalope (see Note 3 – Variable Interest Entities). We recorded our interest in Jackalope as an equity-method investment at its estimated fair value, resulting in a deconsolidation gain of $62 million reflected in Other investing income (loss) – net in the Consolidated Statement of Income. We estimated the fair value of our interest to be $310 million using an income approach based on expected future cash flows and an appropriate discount rate (a Level 3 measurement within the fair value hierarchy). The determination of expected future cash flows involved significant assumptions regarding gathering and processing volumes and related capital spending. A 10.9 percent discount rate was utilized and reflected our estimate of the cost of capital as impacted by market conditions and risks associated with the underlying business. The deconsolidated carrying value of the net assets of Jackalope included $47 million of goodwill.

Acquisition of Additional Interests in Appalachia Midstream Investments

During the first quarter of 2017, we exchanged all of our 50 percent interest in DBJV for an increased interest in two natural gas gathering systems that are part of the Appalachia Midstream Investments and $155 million in cash. This transaction was recorded based on our estimate of the fair value of the interests received as we have more insight to this value as we operate the underlying assets. Following this exchange, we have an approximate average 66 percent interest in the Appalachia Midstream Investments. We continue to account for this investment under the equity method of accounting due to the significant participatory rights of our partners such that we do not exercise control.

We also

Notes (Continued)

sold all of our interest in Ranch Westex JV LLC for $45 million. These transactions resulted in a total gain of $269 million reflected in Other investing income (loss) – net in the Consolidated Statement of Income.
The fair value of the increased interests in the Appalachia Midstream Investments received as consideration was estimated to be $1.1 billion using an income approach based on expected cash flows and an appropriate discount rate (a Level 3 measurement within the fair value hierarchy). The determination of estimated future cash flows involved significant assumptions regarding gathering volumes, rates, and related capital spending. A 9.5 percent discount rate was utilized and reflected our estimate of the cost of capital as impacted by market conditions and risks associated with the underlying business.

Note 6 – Other Income and Expenses

The following table presents certain gains or losses reflected in Other (income) expense – net within Costs and expenses in our Consolidated Statement of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Atlantic-Gulf				
Amortization of regulatory assets associated with asset retirement obligations	$8	$ 8	$24	$25
Accrual of regulatory liability related to overcollection of certain employee expenses	5	5	16	16
Project development costs related to Constitution (see Note 3)	1	4	4	12
Adjustments to regulatory liability related to Tax Reform	—	—	(10)	—
Gain on asset retirement	(10)	(5)	(10)	(5)
West				
Gains on contract settlements and terminations	—	—	—	(15)
Adjustments to regulatory liability related to Tax Reform	—	—	(7)	—
Regulatory charge per approved rates related to Tax Reform	6	—	18	—
Charge for regulatory liability associated with the decrease in Northwest Pipeline’s estimated deferred state income tax rates following WPZ Merger	12	—	12	—
Other				
Benefit of regulatory asset associated with increase in Transco’s estimated deferred state income tax rate following WPZ Merger	(37)	—	(37)	—
Gain on sale of Refinery Grade Propylene Splitter	—	—	—	(12)

Additional Items

Certain additional items included in the Consolidated Statement of Income are as follows:

- Selling, general, and administrative expenses for the three and nine months ended September 30, 2018 includes a $35 million charge associated with a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (a not-for-profit corporation) within the Other segment. (See Note 11 – Stockholders’ Equity.) Selling, general, and administrative expenses for the three and nine months ended September 30, 2018 also includes $15 million and $19 million, respectively, for WPZ Merger related costs within the Other segment. Selling, general, and administrative expenses for the three and nine months ended September 30, 2017 includes $5 million and $18 million, respectively, of severance and other related costs within the Other segment.
- Other income (expense) – net below Operating income (loss) includes income of $33 million and $80 million for the three and nine months ended September 30, 2018, respectively, and $17 million and $55 million for

Notes (Continued)

the three and nine months ended September 30, 2017, respectively, for allowance for equity funds used during construction primarily within the Atlantic-Gulf segment. Other income (expense) – net below Operating income (loss) also includes income of $22 million and $31 million for the three and nine months ended September 30, 2018, respectively, and $8 million and $44 million for the three and nine months ended September 30, 2017, respectively of income associated with a regulatory asset related to deferred taxes on equity funds used during construction. These items are reported primarily within the Other segment.

- Other income (expense) – net below Operating income (loss) for the nine months ended September 30, 2018, includes a $7 million net loss associated with the March 28, 2018, early retirement of $750 million of 4.875 percent senior unsecured notes that were due in 2024. The net loss within the Other segment reflects $34 million in premiums paid, partially offset by $27 million of unamortized premium. (See Note 10 – Debt and Banking Arrangements.) Other income (expense) – net below Operating income (loss) for the three months ended September 30, 2017 includes a net loss of $3 million associated with the July 3, 2017 early retirement of $1.4 billion of 4.875 percent senior unsecured notes that were due in 2023. The net loss for the July 3, 2017 early retirement reflects $54 million in premiums paid, offset by $51 million of unamortized premium. For the nine months ended September 30, 2017, Other income (expense) – net below Operating income (loss) also includes a net gain of $30 million associated with the February 23, 2017, early retirement of $750 million of 6.125 percent senior unsecured notes that were due in 2022. The net gain within the Other segment reflects $53 million of unamortized premium, partially offset by $23 million in premiums paid.

Note 7 – Provision (Benefit) for Income Taxes

The Provision (benefit) for income taxes includes:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Current:				
Federal	$(19)	$7	$(55)	$10
State	—	9	1	17
	(19)	16	(54)	27
Deferred:				
Federal	188	(11)	312	63
State	21	19	39	36
	209	8	351	99
Provision (benefit) for income taxes	$190	$24	$297	$126

The effective income tax rates for the total provision for the three and nine months ended September 30, 2018, are higher than the federal statutory rate primarily due to the effect of state income taxes and a $105 million valuation allowance associated with foreign tax credits, that expire between 2024 and 2027. This is partially offset by the impact of the allocation of income to nontaxable noncontrolling interests. The state income tax provisions include a $38 million provision related to an increase in the deferred state income tax rate (net of federal benefit) partially offset by a net decrease in valuation allowances of $31 million on state net operating losses, both primarily driven by the impact that the completion of the WPZ Merger (see Note 1 – General, Description of Business, and Basis of Presentation) had on income allocation for state tax purposes.

A valuation allowance for deferred tax assets, including foreign tax credits, is recognized when it is more likely than not that some, or all, of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our sources of future taxable income, including available tax planning strategies, to determine whether a valuation allowance is required. The completion of the WPZ Merger decreased our deferred income tax liability by $1.829 billion. Increased tax depreciation from the additional tax basis will reduce taxable income in future years and may limit our ability to realize the full benefit of certain short-lived deferred tax assets.

Notes (Continued)

The effective income tax rate for the three months ended September 30, 2017, is less than the federal statutory rate primarily due to the impact of the allocation of income to nontaxable noncontrolling interests, partially offset by the effect of state income taxes, including an $18 million provision related to an increase in the deferred state income tax rate (net of federal benefit).

The effective income tax rate for the nine months ended September 30, 2017, is less than the federal statutory rate. This is primarily due to the impact of the allocation of income to nontaxable noncontrolling interests and releasing a $127 million valuation allowance on a deferred tax asset associated with a capital loss carryover, partially offset by the effect of state income taxes, including an $18 million provision related to an increase in the deferred state income tax rate (net of federal benefit). In 2016, we recorded a valuation allowance on a deferred tax asset associated with a capital loss that was incurred with the sale of our Canadian operations. The sale of the Geismar olefins facility in 2017 (see Note 4 – Divestitures and Assets Held for Sale) generated capital gains sufficient to offset the capital loss carryover, thereby allowing us to reverse the valuation allowance in full.

On December 22, 2017, Tax Reform was enacted. Under the guidance provided by Securities and Exchange Commission Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act, we recorded provisional adjustments related to the impact of Tax Reform in the fourth quarter of 2017. We consider all amounts recorded related to Tax Reform to be reasonable estimates. The amounts recorded continue to be provisional as our interpretation, assessment, and presentation of the impact of the tax law change may be further clarified with additional guidance from regulatory, tax, and accounting authorities. We anticipate that additional guidance from the Internal Revenue Service will be released to guide us in determining what assets are eligible for direct expensing. We are also recording provisional adjustments for valuation allowances associated with losses and credits since, at this time, we cannot assess the impact that the interest expense disallowance will have on our estimated future taxable income. We are not reducing our minimum tax credit for sequestration until we receive further guidance provided by these authorities or other sources.

During the next 12 months, we do not expect ultimate resolution of any unrecognized tax benefit associated with domestic or international matters to have a material impact on our unrecognized tax benefit position.

Note 8 – Earnings Per Common Share

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Dollars in millions, except per-share amounts; shares in thousands)			
Net income available to common stockholders	$129	$ 33	$416	$ 487
Basic weighted-average shares	1,023,387	826,779	893,706	825,925
Effect of dilutive securities:				
Nonvested restricted stock units	2,387	1,889	2,102	1,567
Stock options	530	700	514	658
Diluted weighted-average shares	1,026,304	829,368	896,322	828,150
Earnings per common share:				
Basic	$.13	$ .04	$.47	$ .59

Diluted	$ .13	$ .04	$ .46	$ .59

Notes (Continued)

Note 9 – Employee Benefit Plans

Net periodic benefit cost (credit) is as follows:

	Pension Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Components of net periodic benefit cost (credit):				
Service cost	$12	$13	$37	$38
Interest cost	12	15	35	44
Expected return on plan assets	(16)	(21)	(47)	(62)
Amortization of net actuarial loss	6	6	17	20
Net actuarial loss from settlements	1	—	2	—
Net periodic benefit cost (credit)	$15	$13	$44	$40

	Other Postretirement Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Components of net periodic benefit cost (credit):				
Service cost	$1	$—	$1	$1
Interest cost	1	2	5	6
Expected return on plan assets	(2)	(3)	(8)	(9)
Amortization of prior service credit	—	(3)	(1)	(10)
Reclassification to regulatory liability	—	1	1	3
Net periodic benefit cost (credit)	$—	$(3)	$(2)	$(9)

The components of Net periodic benefit cost (credit) other than the Service cost component are included in Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Income.

Amortization of prior service credit included in Net periodic benefit cost (credit) for our other postretirement benefit plans associated with Transco and Northwest Pipeline is recorded to regulatory assets/liabilities instead of Other comprehensive income (loss). The amounts of Amortization of prior service credit recognized in regulatory liabilities were $2 million for the three months ended September 30, 2017, and $1 million and $6 million for the nine months ended September 30, 2018 and 2017, respectively.

During the nine months ended September 30, 2018, we contributed $87 million to our pension plans and $4 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $1 million to our pension plans and approximately $2 million to our other postretirement benefit plans in the remainder of 2018.

Note 10 – Debt and Banking Arrangements

Long-Term Debt

Issuances and retirements

On August 24, 2018, Northwest Pipeline issued $250 million of 4 percent senior unsecured notes to investors in a private debt placement. The notes are an additional issuance of Northwest Pipeline’s existing 4 percent senior unsecured notes due 2027. As part of the issuance, Northwest Pipeline entered into a registration rights agreement with the initial purchasers of the unsecured notes. Northwest Pipeline is obligated to file and consummate a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 365 days from closing and to use commercially reasonable efforts to complete the exchange offer. Northwest Pipeline is required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If Northwest Pipeline fails to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of a registration default, increasing by an additional 0.25 percent per annum with respect to each subsequent 90-day period thereafter, up to a maximum amount for all such registration defaults of 0.5 percent annually. Following the cure of any registration defaults, the accrual of additional interest will cease.

Northwest Pipeline retired $250 million of 6.05 percent senior unsecured notes that matured on June 15, 2018.

On March 5, 2018, WPZ completed a public offering of $800 million of 4.85 percent senior unsecured notes due 2048. WPZ used the net proceeds for general partnership purposes, primarily the March 28, 2018 repayment of $750 million of 4.875 percent senior unsecured notes that were due in 2024.

On March 15, 2018, Transco issued $400 million of 4 percent senior unsecured notes due 2028 and $600 million of 4.6 percent senior unsecured notes due 2048 to investors in a private debt placement. Transco used the net proceeds to retire $250 million of 6.05 percent senior unsecured notes that matured on June 15, 2018, and for general corporate purposes, including the funding of capital expenditures. In September 2018, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Other financing obligations

During the first three quarters of 2018, Transco received an additional $29 million of funding from a co-owner related to the construction of the Dalton expansion project. This additional funding is reflected as Long-term debt in the Consolidated Balance Sheet.

During the construction of the Atlantic Sunrise project, Transco received funding from a partner for its proportionate share of construction costs related to an undivided ownership interest in certain parts of the project. Amounts received were recorded within noncurrent liabilities and 100 percent of the costs associated with construction were capitalized in our Consolidated Balance Sheet. Upon placing the project in service during October 2018, Transco began utilizing this partner’s undivided interest in the lateral, including the associated pipeline capacity, and expects to reclassify approximately $790 million of funding previously received from its partner from noncurrent liabilities to debt to reflect the financing obligation payable to its partner over an expected term of 20 years. As this transaction did not meet the criteria for sale leaseback accounting due to our continued involvement, it will be accounted for as a financing arrangement over the course of the capacity agreement.

Commercial Paper Program

On August 10, 2018, following the consummation of the WPZ Merger, WPZ’s $3 billion commercial paper program was discontinued and we entered into a new $4 billion commercial paper program. The maturities of the commercial paper notes vary but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or, alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The net proceeds of issuances of the commercial paper notes are expected to be used to fund planned capital expenditures and for other general corporate purposes. At September 30, 2018, approximately $824 million of Commercial paper at a weighted-average interest rate of 2.73 percent was outstanding. At October 30, 2018, no commercial paper was outstanding.

Notes (Continued)

Credit Facilities

	September 30, 2018	
	Stated Capacity	Outstanding
	(Millions)	
Long-term credit facility (1)	$ 4,500	$ —
Letters of credit under certain bilateral bank agreements		14

(1) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program.

Revolving credit facility

On July 13, 2018, we along with Transco and Northwest Pipeline, the lenders named therein, and an administrative agent entered into a new credit agreement (Credit Agreement) with aggregate commitments available of $4.5 billion, with up to an additional $500 million increase in aggregate commitments available under certain circumstances. On August 10, 2018, following the completion of the WPZ Merger, the Credit Agreement became effective and we terminated both our and WPZ’s existing credit facilities. The maturity date of the new credit facility is August 10, 2023. However, the co-borrowers may request up to two extensions of the maturity date each for an additional one-year period to allow a maturity date as late as August 10, 2025, under certain circumstances. The Credit Agreement allows for swing line loans up to an aggregate of $200 million, subject to available capacity under the new credit facility, and letters of credit commitments of $1 billion. Transco and Northwest Pipeline are each able to borrow up to $500 million under this credit facility to the extent not otherwise utilized by the other co-borrowers.

The Credit Agreement contains the following terms and conditions:

- Various covenants may limit, among other things, a borrower's and its material subsidiaries' ability to grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, make certain distributions during an event of default, and enter into certain restrictive agreements.
- If an event of default with respect to a borrower occurs under the credit facility, the lenders will be able to terminate the commitments and accelerate the maturity of the loans and exercise other rights and remedies.
- Other than swing line loans, each time funds are borrowed, the applicable borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A.'s adjusted base rate plus an applicable margin or a periodic fixed rate equal to the London Interbank Offered Rate plus an applicable margin. We are required to pay a commitment fee based on the unused portion of the credit facility. The applicable margin and the commitment fee are determined by reference to a pricing schedule based on the applicable borrower’s senior unsecured long-term debt ratings.

Significant financial covenants under the Credit Agreement require the ratio of debt to EBITDA (earnings before interest, taxes, depreciation, and amortization), each as defined in the credit facility, to be no greater than:

- 5.75 to 1 for each fiscal quarter end through June 30, 2019;
- 5.5 to 1 for the fiscal quarters ending September 30, 2019, and December 31, 2019;
- 5.0 to 1 for the fiscal quarter ending March 31, 2020, and each subsequent fiscal quarter end, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions with a total aggregate purchase price of $25 million or more has been executed, in which case the ratio of debt to EBITDA is to be no greater than 5.5 to 1.

Notes (Continued)

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each of Transco and Northwest Pipeline.
At September 30, 2018, we are in compliance with these covenants.
Note 11 – Stockholders' Equity
Issuance of Preferred Shares
In July 2018, through a wholly owned subsidiary, we contributed 35,000 shares of newly issued Series B Non-Voting Perpetual Preferred Stock (Preferred Stock) to The Williams Companies Foundation, Inc. (a not-for-profit corporation) for use in future charitable and nonprofit causes. The charitable contribution of Preferred Stock was recorded as an expense in the third quarter of 2018. The Preferred Stock was issued for an aggregate value of $35 million and pays non-cumulative quarterly cash dividends when, as and if declared, at a rate of 7.25 percent per year. We paid dividends totaling $0.4 million on the shares of Preferred Stock in September 2018. Our certificate of incorporation authorizes 30 million shares of Preferred Stock, $1 par value per share.
AOCI
The following table presents the changes in Accumulated other comprehensive income (loss) (AOCI) by component, net of income taxes:

	Cash Flow Hedges	Foreign Currency Translation	Pension and Other Postretirement Benefits	Total
	(Millions)			
Balance at December 31, 2017	$(2)	$ (1)	$ (235)	$(238)
Adoption of ASU 2018-02 (Note 1)	—	—	(61)	(61)
WPZ Merger (Note 1)	(3)	—	—	(3)
Other comprehensive income (loss):				
Other comprehensive income (loss) before reclassifications	(14)	—	4	(10)
Amounts reclassified from accumulated other comprehensive income (loss)	7	—	14	21
Other comprehensive income (loss)	(7)	—	18	11
Balance at September 30, 2018	$(12)	$ (1)	$ (278)	$(291)

Notes (Continued)

Reclassifications out of AOCI are presented in the following table by component for the nine months ended September 30, 2018:

Component	Reclassifications (Millions)	Classification
Cash flow hedges:		
Energy commodity contracts	$ 13	Product sales
Pension and other postretirement benefits:		
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit)	19	Note 9 – Employee Benefit Plans
Total before tax	32	
Income tax benefit	(8)	Provision (benefit) for income taxes
Net of income tax	24	
Noncontrolling interest	(3)	Net income (loss) attributable to noncontrolling interests
Reclassifications during the period	$ 21	

Notes (Continued)

Note 12 – Fair Value Measurements and Guarantees

The following table presents, by level within the fair value hierarchy, certain of our financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable, commercial paper, and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(Millions)				
Assets (liabilities) at September 30, 2018:					
Measured on a recurring basis:					
ARO Trust investments	$ 157	$ 157	$ 157	$ —	$ —
Energy derivatives assets not designated as hedging instruments	6	6	6	—	—
Energy derivatives liabilities designated as hedging instruments	(14)	(14)	(13)	(1)	—
Energy derivatives liabilities not designated as hedging instruments	(9)	(9)	(6)	—	(3)
Additional disclosures:					
Other receivables	21	21	21	—	—
Long-term debt, including current portion	(21,442)	(22,532)	—	(22,532)	—
Guarantees	(43)	(30)	—	(14)	(16)
Assets (liabilities) at December 31, 2017:					
Measured on a recurring basis:					
ARO Trust investments	$ 135	$ 135	$ 135	$ —	$ —
Energy derivatives liabilities designated as hedging instruments	(3)	(3)	(2)	(1)	—
Energy derivatives liabilities not designated as hedging instruments	(3)	(3)	—	—	(3)
Additional disclosures:					
Other receivables	7	7	7	—	—
Long-term debt, including current portion	(20,935)	(23,005)	—	(23,005)	—
Guarantees	(43)	(30)	—	(14)	(16)

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets and liabilities measured at fair value on a recurring basis

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its rate case settlement, into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations (ARO). The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted prices in an active market and is reported in Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Energy derivatives: Energy derivatives include commodity-based exchange-traded contracts and over-the-counter contracts, which consist of physical forwards, futures, and swaps that are measured at fair value on a recurring basis.

The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions

Notes (Continued)

permitted under the terms of our master netting arrangements. Further, the amounts do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Energy derivatives assets are reported in Other current assets and deferred charges and Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet. Energy derivatives liabilities are reported in Accrued liabilities and Regulatory liabilities, deferred income, and other in the Consolidated Balance Sheet.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No transfers between Level 1 and Level 2 occurred during the nine months ended September 30, 2018 or 2017.

Additional fair value disclosures

Other receivables: Other receivables consist of margin deposits, which are reported in Other current assets and deferred charges in the Consolidated Balance Sheet. The disclosed fair value of our margin deposits is considered to approximate the carrying value generally due to the short-term nature of these items.

Long-term debt, including current portion: The disclosed fair value of our long-term debt is determined primarily by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments.

Guarantees: Guarantees primarily consist of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a lease performance obligation that extends through 2042. Guarantees also include an indemnification related to a disposed operation.

To estimate the fair value of the WilTel guarantee, an estimated default rate is applied to the sum of the future contractual lease payments using an income approach. The estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of WilTel’s current owner and the term of the underlying obligation. The default rate is published by Moody’s Investors Service. The carrying value of the WilTel guarantee is reported in Accrued liabilities in the Consolidated Balance Sheet. The maximum potential undiscounted exposure is approximately $29 million at September 30, 2018. Our exposure declines systematically through the remaining term of WilTel’s obligation.

The fair value of the guarantee associated with the indemnification related to a disposed operation was estimated using an income approach that considered probability-weighted scenarios of potential levels of future performance. The terms of the indemnification do not limit the maximum potential future payments associated with the guarantee. The carrying value of this guarantee is reported in Regulatory liabilities, deferred income, and other in the Consolidated Balance Sheet.

We are required by our revolving credit agreement to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

Nonrecurring fair value measurements

The following table presents impairments of assets associated with certain nonrecurring fair value measurements within Level 3 of the fair value hierarchy, except as specifically noted.

Notes (Continued)

	Classification	Segment	Date of Measurement	Fair Value	Impairments Nine Months Ended September 30, 2018	2017
				(Millions)		
Certain idle pipeline assets (1)	Property, plant, and equipment – net	Other	June 30, 2018	$25	$66	
Certain gathering operations (2)	Property, plant, and equipment – net and Intangible assets - net of accumulated amortization	West	September 30, 2017	439		$1,019
Certain gathering operations (3)	Property, plant, and equipment – net and Intangible assets - net of accumulated amortization	Northeast G&P	September 30, 2017	21		115
Certain NGL pipeline (4)	Property, plant, and equipment – net	Other	September 30, 2017	32		68
Certain olefins pipeline project (5)	Property, plant, and equipment – net	Other	June 30, 2017	18		23
Fair value measurements of certain assets					66	1,225
Other impairments and write-downs (6)					—	11
Impairment of certain assets					$66	$1,236

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(1) Relates to certain idle pipelines. The estimated fair value was determined by a market approach incorporating information derived from bids received for these assets, which are currently being marketed for sale together with certain other assets. These inputs result in a fair value measurement within Level 2 of the fair value hierarchy.

(2) Relates to certain gathering operations in the Mid-Continent region. During the third quarter of 2017, we received solicitations and engaged in negotiations for the sale of certain of these assets which led to our impairment evaluation. The estimated fair value was determined using an income approach and incorporated market inputs based on ongoing negotiations for a potential sale of a portion of the underlying assets. For the income approach, we utilized a discount rate of 10.2 percent, reflecting an estimated cost of capital and risks associated with the underlying assets.

(3) Relates to certain gathering operations in the Marcellus South region resulting from an anticipated decline in future volumes following a third-quarter 2017 shut-in by the primary producer. The estimated fair value was determined by the income approach utilizing a discount rate of 11.1 percent, reflecting an estimated cost of capital and risks associated with the underlying assets.

(4)

Relates to an NGL pipeline near the Houston Ship Channel region which we anticipate will be underutilized for the foreseeable future. The estimated fair value was primarily determined by using a market approach based on our analysis of observable inputs in the principal market.

Notes (Continued)

(5) Relates primarily to project development costs associated with an olefins pipeline project in the Gulf Coast region, the likelihood of completion of which is now considered remote. The estimated fair value of the remaining pipe and equipment considered a market approach based on our analysis of observable inputs in the principal market, as well as an estimate of replacement cost.

(6) Reflects multiple individually insignificant impairments and write-downs of other certain assets that may no longer be in use or are surplus in nature for which the fair value was determined to be lower than the carrying value.

Note 13 – Contingent Liabilities

Reporting of Natural Gas-Related Information to Trade Publications

Direct and indirect purchasers of natural gas in various states filed individual and class actions against us, our former affiliate WPX Energy, Inc. (WPX) and its subsidiaries, and others alleging the manipulation of published gas price indices and seeking unspecified amounts of damages. Such actions were transferred to the Nevada federal district court for consolidation of discovery and pre-trial issues. We have agreed to indemnify WPX and its subsidiaries related to this matter.

In the individual action, filed by Farmland Industries Inc. (Farmland), the court issued an order on May 24, 2016, granting one of our co-defendant's motion for summary judgment as to Farmland's claims. On January 5, 2017, the court extended such ruling to us, entering final judgment in our favor. Farmland appealed. On March 27, 2018, the appellate court reversed the district court's grant of summary judgment, and on April 10, 2018, the defendants filed a petition for rehearing with the appellate court, which was denied on May 9, 2018. The case has been remanded to the Nevada federal district court.

In the putative class actions, on March 30, 2017, the court issued an order denying the plaintiffs' motions for class certification. On June 13, 2017, the United States Court of Appeals for the Ninth Circuit granted the plaintiffs' petition for permission to appeal the order. On August 6, 2018, the Ninth Circuit reversed the order denying class certification and remanded the case to the Nevada federal district court.

Because of the uncertainty around the remaining pending unresolved issues, we cannot reasonably estimate a range of potential exposure at this time. However, it is reasonably possible that the ultimate resolution of these actions and our related indemnification obligation could result in a potential loss that may be material to our results of operations. In connection with this indemnification, we have an accrued liability balance associated with this matter, and as a result, have exposure to future developments.

Alaska Refinery Contamination Litigation

We are involved in litigation arising from our ownership and operation of the North Pole Refinery in North Pole, Alaska, from 1980 until 2004, through our wholly owned subsidiaries, Williams Alaska Petroleum Inc. (WAPI) and MAPCO Inc. We sold the refinery to Flint Hills Resources Alaska, LLC (FHRA), a subsidiary of Koch Industries, Inc., in 2004. The litigation involves three cases, with filing dates ranging from 2010 to 2014. The actions arise from sulfolane contamination allegedly emanating from the refinery. A putative class action lawsuit was filed by James West in 2010 naming us, WAPI, and FHRA as defendants. We and FHRA filed claims against each other seeking, among other things, contractual indemnification alleging that the other party caused the sulfolane contamination. In 2011, we and FHRA settled the claim with James West. Certain claims by FHRA against us were resolved by the Alaska Supreme Court in our favor. FHRA's claims against us for contractual indemnification and statutory claims for damages related to off-site sulfolane remain pending. The State of Alaska filed its action in March 2014, seeking damages. The City of North Pole (North Pole) filed its lawsuit in November 2014, seeking past and future damages, as well as punitive damages. Both we and WAPI asserted counterclaims against the State of Alaska and North Pole, and cross-claims against FHRA. FHRA has also filed cross-claims against us.

The underlying factual basis and claims in the cases are similar and may duplicate exposure. As such, in February 2017, the three cases were consolidated into one action in state court containing the remaining claims from

Notes (Continued)

the James West case and those of the State of Alaska and North Pole. A trial encompassing all three cases was originally scheduled to commence in May 2017 but has been rescheduled for March 2019. Due to the ongoing assessment of the level and extent of sulfolane contamination, the lack of an articulated cleanup level for sulfolane, and the lack of a concrete remedial proposal and cost estimate, we are unable to estimate a range of exposure to the State of Alaska or North Pole at this time. We currently estimate that our reasonably possible loss exposure to FHRA could range from an insignificant amount up to $32 million, although uncertainties inherent in the litigation process, expert evaluations, and jury dynamics might cause our exposure to exceed that amount.

Independent of the litigation matter described in the preceding paragraphs, in 2013, the Alaska Department of Environmental Conservation indicated that it views FHRA and us as responsible parties, and that it intends to enter a compliance order to address the environmental remediation of sulfolane and other possible contaminants including cleanup work outside the refinery’s boundaries. To date, no compliance order has been issued. Due to the ongoing assessment of the level and extent of sulfolane contamination, the ultimate cost of remediation and division of costs among the potentially responsible parties, and the previously described separate litigation, we are unable to estimate a range of exposure at this time.

Royalty Matters

Certain of our customers, including one major customer, have been named in various lawsuits alleging underpayment of royalties and claiming, among other things, violations of anti-trust laws and the Racketeer Influenced and Corrupt Organizations Act. We have also been named as a defendant in certain of these cases filed in Pennsylvania based on allegations that we improperly participated with that major customer in causing the alleged royalty underpayments. We believe that the claims asserted are subject to indemnity obligations owed to us by that major customer. That customer has reached a tentative settlement to resolve substantially all Pennsylvania royalty cases pending, which settlement would apply to both the customer and us. The settlement as reported would not require any contribution from us.

Litigation Against Energy Transfer and Related Parties

On April 6, 2016, we filed suit in Delaware Chancery Court against Energy Transfer Equity, L.P. (Energy Transfer) and LE GP, LLC (the general partner for Energy Transfer) alleging willful and material breaches of the Agreement and Plan of Merger (ETE Merger Agreement) with Energy Transfer resulting from the private offering by Energy Transfer on March 8, 2016, of Series A Convertible Preferred Units (Special Offering) to certain Energy Transfer insiders and other accredited investors. The suit seeks, among other things, an injunction ordering the defendants to unwind the Special Offering and to specifically perform their obligations under the ETE Merger Agreement. On April 19, 2016, we filed an amended complaint seeking the same relief. On May 3, 2016, Energy Transfer and LE GP, LLC filed an answer and counterclaims.

On May 13, 2016, we filed a separate complaint in Delaware Chancery Court against Energy Transfer, LE GP, LLC, and the other Energy Transfer affiliates that are parties to the ETE Merger Agreement, alleging material breaches of the ETE Merger Agreement for failing to cooperate and use necessary efforts to obtain a tax opinion required under the ETE Merger Agreement (Tax Opinion) and for otherwise failing to use necessary efforts to consummate the merger under the ETE Merger Agreement wherein we would be merged with and into the newly formed Energy Transfer Corp LP (ETC) (ETC Merger). The suit sought, among other things, a declaratory judgment and injunction preventing Energy Transfer from terminating or otherwise avoiding its obligations under the ETE Merger Agreement due to any failure to obtain the Tax Opinion.

The Court of Chancery coordinated the Special Offering and Tax Opinion suits. On May 20, 2016, the Energy Transfer defendants filed amended affirmative defenses and verified counterclaims in the Special Offering and Tax Opinion suits, alleging certain breaches of the ETE Merger Agreement by us and seeking, among other things, a declaration that we were not entitled to specific performance, that Energy Transfer could terminate the ETC Merger, and that Energy Transfer is entitled to a $1.48 billion termination fee. On June 24, 2016, following a two-day trial, the court issued a Memorandum Opinion and Order denying our requested relief in the Tax Opinion suit. The court did not rule on the substance of our claims related to the Special Offering or on the substance of Energy Transfer’s counterclaims. On June 27, 2016, we filed an appeal of the court’s decision with the Supreme Court of Delaware, seeking reversal and

Notes (Continued)

remand to pursue damages. On March 23, 2017, the Supreme Court of Delaware affirmed the Court of Chancery's ruling. On March 30, 2017, we filed a motion for reargument with the Supreme Court of Delaware, which was denied on April 5, 2017.

On September 16, 2016, we filed an amended complaint with the Court of Chancery seeking damages for breaches of the ETE Merger Agreement by defendants. On September 23, 2016, Energy Transfer filed a second amended and supplemental affirmative defenses and verified counterclaim with the Court of Chancery seeking, among other things, payment of the $1.48 billion termination fee due to our alleged breaches of the ETE Merger Agreement. On December 1, 2017, the court granted our motion to dismiss certain of Energy Transfer's counterclaims, including its claim seeking payment of the $1.48 billion termination fee. On December 8, 2017, Energy Transfer filed a motion for reargument, which the Court of Chancery denied on April 16, 2018. The Court of Chancery scheduled trial for May 20 through May 24, 2019.

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations, and/or remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. As of September 30, 2018, we have accrued liabilities totaling $36 million for these matters, as discussed below. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies, or our experience with other similar cleanup operations. At September 30, 2018, certain assessment studies were still in process for which the ultimate outcome may yield different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, air quality standards for one-hour nitrogen dioxide emissions, and volatile organic compound and methane new source performance standards impacting design and operation of storage vessels, pressure valves, and compressors. On October 1, 2015, the EPA issued its rule regarding National Ambient Air Quality Standards for ground-level ozone, setting a stricter standard of 70 parts per billion. We are monitoring the rule's implementation as the reduction will trigger additional federal and state regulatory actions that may impact our operations. Implementation of the regulations is expected to result in impacts to our operations and increase the cost of additions to Property, plant, and equipment – net in the Consolidated Balance Sheet for both new and existing facilities in affected areas. We are unable to reasonably estimate the cost of additions that may be required to meet the regulations at this time due to uncertainty created by various legal challenges to these regulations and the need for further specific regulatory guidance.

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At September 30, 2018, we have accrued liabilities of $7 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2018, we have accrued liabilities totaling $7 million for these costs.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include remediation activities at the direction of federal and state environmental authorities and the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities relate to the operations of the assets and businesses described below.

- Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;
- Former petroleum products and natural gas pipelines;
- Former petroleum refining facilities;
- Former exploration and production and mining operations;
- Former electricity and natural gas marketing and trading operations.

At September 30, 2018, we have accrued environmental liabilities of $22 million related to these matters.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, property damage, environmental matters, right of way, and other representations that we have provided.

At September 30, 2018, other than as previously disclosed, we are not aware of any material claims against us involving the indemnities; thus, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. Any claim for indemnity brought against us in the future may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations, none of which are expected to be material to our expected future annual results of operations, liquidity, and financial position.

Summary

We have disclosed our estimated range of reasonably possible losses for certain matters above, as well as all significant matters for which we are unable to reasonably estimate a range of possible loss. We estimate that for all other matters for which we are able to reasonably estimate a range of loss, our aggregate reasonably possible losses beyond amounts accrued are immaterial to our expected future annual results of operations, liquidity, and financial position. These calculations have been made without consideration of any potential recovery from third parties.

Note 14 – Segment Disclosures

Our reportable segments are Northeast G&P, Atlantic-Gulf, and West. All remaining business activities are included in Other. (See Note 1 – General, Description of Business, and Basis of Presentation.)

Performance Measurement

We evaluate segment operating performance based upon Modified EBITDA. This measure represents the basis of our internal financial reporting and is the primary performance measure used by our chief operating decision maker in

Notes (Continued)

measuring performance and allocating resources among our reportable segments. Intersegment revenues primarily represent the sale of NGLs from our natural gas processing plants to our marketing business.

We define Modified EBITDA as follows:

- Net income (loss) before:
  - Income (loss) from discontinued operations;
  - Provision (benefit) for income taxes;
  - Interest incurred, net of interest capitalized;
  - Equity earnings (losses);
  - Gain on remeasurement of equity-method investment;
  - Impairment of equity-method investments;
  - Other investing income (loss) – net;
  - Impairment of goodwill;
  - Depreciation and amortization expenses;
  - Accretion expense associated with asset retirement obligations for nonregulated operations.
- This measure is further adjusted to include our proportionate share (based on ownership interest) of Modified EBITDA from our equity-method investments calculated consistently with the definition described above.

Notes (Continued)

The following table reflects the reconciliation of Segment revenues to Total revenues as reported in the Consolidated Statement of Income and Total assets by reportable segment.

	Northeast G&P	Atlantic-Gulf	West	Other (1)	Eliminations (2)	Total
	(Millions)					
Three Months Ended September 30, 2018						
Segment revenues:						
Service revenues						
External	$236	$ 595	$533	$ 7	$ —	$1,371
Internal	11	12	—	3	(26)	—
Total service revenues	247	607	533	10	(26)	1,371
Total service revenues – commodity consideration (external only)	6	18	97	—	—	121
Product sales						
External	59	46	706	—	—	811
Internal	10	85	26	—	(121)	—
Total product sales	69	131	732	—	(121)	811
Total revenues	$322	$ 756	$1,362	$ 10	$ (147)	$2,303
Three Months Ended September 30, 2017						
Segment revenues:						
Service revenues						
External	$207	$ 553	$544	$ 6	$ —	$1,310
Internal	7	11	—	3	(21)	—
Total service revenues	214	564	544	9	(21)	1,310
Product sales						
External	56	57	459	9	—	581
Internal	5	49	26	—	(80)	—
Total product sales	61	106	485	9	(80)	581
Total revenues	$275	$ 670	$1,029	$ 18	$ (101)	$1,891
Nine Months Ended September 30, 2018						
Segment revenues:						
Service revenues						
External	$677	$ 1,769	$1,599	$ 17	$ —	$4,062
Internal	30	37	—	9	(76)	—
Total service revenues	707	1,806	1,599	26	(76)	4,062
Total service revenues – commodity consideration (external only)	14	45	257	—	—	316
Product sales						
External	214	131	1,759	—	—	2,104
Internal	28	198	63	—	(289)	—
Total product sales	242	329	1,822	—	(289)	2,104
Total revenues	$963	$ 2,180	$3,678	$ 26	$ (365)	$6,482

Notes (Continued)

	Northeast G&P	Atlantic-Gulf	West	Other (1)	Eliminations (2)	Total
	(Millions)					
Nine Months Ended September 30, 2017						
Segment revenues:						
Service revenues						
External	$621	$ 1,620	$1,589	$23	$ —	$3,853
Internal	27	27	—	9	(63)	—
Total service revenues	648	1,647	1,589	32	(63)	3,853
Product sales						
External	159	201	1,233	357	—	1,950
Internal	22	164	143	8	(337)	—
Total product sales	181	365	1,376	365	(337)	1,950
Total revenues	$829	$ 2,012	$2,965	$397	$ (400)	$5,803
September 30, 2018						
Total assets	$14,482	$ 16,361	$16,169	$748	$ (607)	$47,153
December 31, 2017						
Total assets	$14,397	$ 14,989	$16,143	$1,449	$ (626)	$46,352

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(1) Decrease in Other Total assets due primarily to decreased cash balance.

(2) Total assets Eliminations primarily relate to the intercompany notes and accounts receivable generated by our cash management program.

The following table reflects the reconciliation of Modified EBITDA to Net income (loss) as reported in the Consolidated Statement of Income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Modified EBITDA by segment:				
Northeast	$281	$115	$786	$588
Atlantic-Gulf	492	430	1,418	1,334
West	412	(615)	1,214	126
Other	6	1,009	(49)	1,100
	1,191	939	3,369	3,148
Accretion expense associated with asset retirement obligations for nonregulated operations	(8)	(7)	(26)	(23)
Depreciation and amortization expenses	(425)	(433)	(1,290)	(1,308)
Equity earnings (losses)	105	115	279	347
Other investing income (loss) – net	2	4	74	278
Proportional Modified EBITDA of equity-method investments	(205)	(202)	(552)	(611)
Interest expense	(270)	(267)	(818)	(818)
(Provision) benefit for income taxes	(190)	(24)	(297)	(126)

Net income (loss)	$200	$125	$739	$887

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Item 2
Management's Discussion and Analysis of
Financial Condition and Results of Operations
General
We are an energy infrastructure company focused on connecting North America's significant hydrocarbon resource plays to growing markets for natural gas and NGLs through our gas pipeline and midstream businesses.
Our interstate natural gas pipeline strategy is to create value by maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets. Our gas pipeline businesses' interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's ratemaking process. Changes in commodity prices and volumes transported have limited near-term impact on these revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.
The ongoing strategy of our midstream operations is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers. These services include natural gas gathering, processing, treating, and compression, NGL fractionation and transportation, crude oil production handling and transportation, marketing services for NGL, crude oil and natural gas, as well as storage facilities.
Prior to the WPZ Merger, we had one reportable segment, Williams Partners. Beginning in the third-quarter 2018, consistent with the manner in which our chief operating decision maker evaluates performance and allocates resources, our operations are now presented within the following reportable segments: Northeast G&P, Atlantic-Gulf, and West. Prior period segment disclosures have been recast for the new segment presentation. Our reportable segments are comprised of the following businesses:

- Northeast G&P is comprised of our midstream gathering and processing businesses in the Marcellus Shale region primarily in Pennsylvania, New York, and West Virginia and the Utica Shale region of eastern Ohio, as well as a 66 percent interest in Cardinal (a consolidated entity), a 62 percent equity-method investment in UEOM, a 69 percent equity-method investment in Laurel Mountain, a 58 percent equity-method investment in Caiman II, and Appalachia Midstream Services, LLC, which owns equity-method investments with an approximate average 66 percent interest in multiple gas gathering systems in the Marcellus Shale (Appalachia Midstream Investments).
- Atlantic-Gulf is comprised of our interstate natural gas pipeline, Transco, and significant natural gas gathering and processing and crude oil production handling and transportation assets in the Gulf Coast region, including a 51 percent interest in Gulfstar One (a consolidated entity), which is a proprietary floating production system, and various petrochemical and feedstock pipelines in the Gulf Coast region, as well as a 50 percent equity-method investment in Gulfstream, a 60 percent equity-method investment in Discovery, and a 41 percent interest in Constitution (a consolidated entity), which is developing a pipeline project (see Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements).

Management's Discussion and Analysis (Continued)

- West is comprised of our interstate natural gas pipeline, Northwest Pipeline, and our gathering, processing, and treating operations in New Mexico, Colorado, and Wyoming, as well as the Barnett Shale region of north-central Texas, the Eagle Ford Shale region of south Texas, the Haynesville Shale region of northwest Louisiana, and the Mid-Continent region which includes the Anadarko, Arkoma, Delaware, and Permian basins. This segment also includes our NGL and natural gas marketing business, storage facilities, an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, and a 50 percent equity-method investment in OPPL, a 50 percent interest in Jackalope (an equity-method investment following deconsolidation as of June 30, 2018), a 43 percent equity-method investment in RMM, and our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 5 – Investing Activities of Notes to Consolidated Financial Statements).

All remaining business activities, including our former Geismar Interest (see Note 4 – Divestitures and Assets Held for Sale of Notes to Consolidated Financial Statements), as well as corporate activities, are included in Other.

Financial Repositioning

In January 2017, we entered into agreements with WPZ, wherein we permanently waived the general partner's IDRs and converted our 2 percent general partner interest in WPZ to a noneconomic interest in exchange for 289 million newly issued WPZ common units. Pursuant to this agreement, we also purchased approximately 277 thousand WPZ common units for $10 million. Additionally, we purchased approximately 59 million common units of WPZ at a price of $36.08586 per unit in a private placement transaction, funded with proceeds from our equity offering. According to the terms of this agreement, concurrent with WPZ's quarterly distributions in February 2017 and May 2017, we paid additional consideration totaling $56 million to WPZ for these units.

Dividends

In September 2018, we paid a regular quarterly dividend of $0.34 per share.

Overview of Nine Months Ended September 30, 2018

Net income (loss) attributable to The Williams Companies, Inc., for the nine months ended September 30, 2018, decreased $71 million compared to the nine months ended September 30, 2017, reflecting a $204 million decrease in Other investing income (loss) due to the absence of a $269 million gain associated with the disposition of certain equity-method investments in 2017, a $171 million increase to the provision for income taxes which reflects a $105 million valuation allowance on certain deferred tax assets that may not be realized following the WPZ Merger and the absence of a prior year $127 million benefit associated with the release of a valuation allowance on a capital loss carryover, and a $68 million decrease in Equity earnings (losses). These decreases were partially offset by an increase of $320 million in operating income and a $77 million decrease to Net income (loss) attributable to noncontrolling interests primarily due to the WPZ Merger.

The improvement in operating income reflects a decrease of $1.170 billion in Impairment of certain assets, a $209 million increase in service revenues primarily resulting from expansion projects placed into service in 2017 and 2018, and a $64 million increase in NGL margins. These favorable changes were partially offset by the absence of a $1.095 billion gain from the sale of our Geismar Interest in 2017.

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition and liquidity should be read in conjunction with the consolidated financial statements and notes thereto of this Form 10 Q and our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 3, 2018.

WPZ Merger

On August 10, 2018, we completed our merger with Williams Partners L.P. (WPZ), pursuant to which we acquired all of the approximately 256 million publicly held outstanding common units of WPZ in exchange for 382 million shares of our common stock in a non-cash equity transaction. Williams continued as the surviving entity. (See Note 1 – General, Description of Business, and Basis of Presentation of Notes to Consolidated Financial Statements.)

Management's Discussion and Analysis (Continued)

FERC Income Tax Policy Revision

On March 15, 2018, the FERC issued a revised policy statement (the March 15 Statement) regarding the recovery of income tax costs in rates of natural gas pipelines. The FERC found that an impermissible double recovery results from granting a Master Limited Partnership (MLP) pipeline both an income tax allowance and a return on equity pursuant to the discounted cash flow methodology. As a result, the FERC will no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. The FERC further stated it will address the application of this policy to non-MLP partnership forms as those issues arise in subsequent proceedings. One of the benefits of the recent WPZ Merger is to allow our FERC-regulated pipelines to continue to recover an income tax allowance in their cost of service rates.

On July 18, 2018, the FERC issued an order dismissing the requests for rehearing and clarification of the revised policy statement. In addition, the FERC provided guidance that an MLP pipeline (or other pass-through entity) no longer recovering an income tax allowance pursuant to the revised policy may eliminate previously accumulated deferred income taxes (ADIT) from its cost of service instead of flowing these ADIT balances to ratepayers. This guidance, if implemented, would significantly mitigate the impact of the March 15 Statement. However, the FERC stated that the revised policy statement and such guidance do not establish a binding rule but are instead expressions of general policy intent designed to provide guidance by notifying entities of the course of action the FERC intends to follow in future adjudications. To the extent the FERC addresses these issues in future proceedings, it will consider any arguments regarding not only the application of the revised policy to the facts of the case, but also any arguments regarding the underlying validity of the policy itself. The FERC's guidance on ADIT likely will be challenged by customers and state commissions, which would result in a long period of revenue uncertainty for pipelines eliminating ADIT from their cost of service. The WPZ Merger has the additional benefit of eliminating this uncertainty.

On March 15, 2018, the FERC also issued a Notice of Proposed Rulemaking proposing a filing process that will allow it to determine which natural gas pipelines may be collecting unjust and unreasonable rates in light of the recent reduction in the corporate income tax rate in the Tax Cuts and Jobs Act (Tax Reform) and the revised policy statement. On July 18, 2018, the FERC issued a Final Rule, retaining the filing requirement and reaffirming the options that pipelines have to either reflect the reduced tax rate or explain why no rate change is necessary. The FERC also clarified that a natural gas company organized as a pass-through entity and all of whose income or losses are consolidated on the federal income tax return of its corporate parent is considered to be subject to the federal corporate income tax and is thus eligible for a tax allowance. We believe this Final Rule and the previously discussed WPZ Merger allow for the continued recovery of income tax allowances in Transco's and Northwest Pipeline's rates. Further, Transco's August 31, 2018 general rate case filing reflects a tax allowance based on this clarification, and the FERC's September 28, 2018 order in the rate case proceeding finds that Transco is exempt from the Final Rule's Form 501-G filing requirement. In addition, on October 19, 2018, Northwest Pipeline filed a petition requesting that the FERC waive its Form 501-G filing requirement under this Final Rule because the reduction in the corporate income tax in Tax Reform is already addressed in its settlement.

On March 15, 2018, the FERC also issued a Notice of Inquiry seeking comments on the additional impacts of Tax Reform on jurisdictional rates, particularly whether, and if so how, the FERC should address changes relating to ADIT amounts after the corporate income tax rate reduction and bonus depreciation rules, as well as whether other features of Tax Reform require FERC action. We are evaluating the impact of these developments on our interstate natural gas pipelines and currently expect any associated impacts would be prospective and determined through subsequent rate proceedings. We also continue to monitor developments that may impact our regulatory liabilities resulting from Tax Reform. It is reasonably possible that future tariff-based rates collected by our interstate natural gas pipelines may be adversely impacted.

Proposition 112

On November 6, 2018, citizens of Colorado will vote on Proposition 112, a ballot measure that could significantly increase setback distances from occupied structures or other vulnerable areas, as defined or designated, for any new oil and gas development in the state, critically restricting or banning such activities. If the measure is approved, it could still be subject to modification or amendment by the Colorado legislature. An unfavorable outcome could adversely

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impact the operations, and ultimately the value, of our businesses and investments in Colorado, notably our recent investment in RMM.

Revenue Recognition

As a result of the adoption of Accounting Standards Update 2014-09, Revenues from Contracts with Customers (ASC 606), we now record revenues for transactions where we receive noncash consideration, primarily in certain of our gas processing contracts that provide commodities as full or partial consideration for services provided. These revenues are reflected as Service revenues – commodity consideration in the Consolidated Statement of Income. The costs associated with these revenues, primarily related to natural gas shrink replacement, are reported as Processing commodity expenses. The revenues and costs associated with the subsequent sale of the commodity consideration received is reflected within Product sales and Product costs in the Consolidated Statement of Income. Service revenues – commodity consideration plus Product sales, less Product costs and Processing commodity expenses represents the margin that we have historically characterized as commodity margin. This presentation is being reflected prospectively in the Consolidated Statement of Income. (See Note 2 – Revenue Recognition of Notes to Consolidated Financial Statements.)

Additionally, future revenues are impacted by application of the new accounting standard to certain contracts for which we received prepayments for services and have recorded deferred revenue (contract liabilities). For these contracts, which underwent modifications in periods prior to January 1, 2018, the modification is treated as a termination of the existing contract and the creation of a new contract. The new accounting guidance requires that the transaction price, including any remaining deferred revenue from the old contract, be allocated to the performance obligations over the term of the new contract. As a result, we will recognize the deferred revenue over longer periods than application of revenue recognition under accounting guidance prior to January 1, 2018. The application of ASC 606 to prior periods related to these contracts would have resulted in lower revenues in 2017. Annual revenues will also be lower in 2018 and 2019 than what would have been recorded under the previous guidance, offset by increased revenues in later reporting periods given the longer period of recognition.

Filing of Rate Case

On August 31, 2018, Transco filed a general rate case with the FERC for an overall increase in rates. In September 2018, with the exception of certain rates that reflected a rate decrease, the FERC accepted and suspended our general rate filing to be effective March 1, 2019, subject to refund and the outcome of a hearing. The specific rates that reflected a rate decrease were accepted, without suspension, to be effective October 1, 2018, as requested by Transco, and will not be subject to refund. The impact of these specific new rates is expected to reduce revenues by approximately $2.5 million per month beginning October 1, 2018.

RMM Equity-Method Investment

During the third quarter of 2018, our joint venture, RMM, purchased a natural gas and oil gathering and natural gas processing business in Colorado's Denver-Julesburg basin. Our initial economic ownership was 40 percent, which is expected to increase to 50 percent as we provide additional capital contributions. At September 30, 2018, our carrying value was $569 million reflecting our 43 percent economic ownership. We are committed to fund up to an additional $177 million to reach 50 percent economic ownership, to the extent RMM needs funding for capital expenditures. We account for this investment under the equity method of accounting.

Divestment of Four Corners Assets

On October 1, 2018, we completed the sale of our natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado for total consideration of $1.125 billion, subject to customary working capital adjustments, of which a $113 million deposit was received in the third quarter. At September 30, 2018, these assets were designated as held for sale within the West segment. As a result of this sale, we expect to record a gain of approximately $0.6 billion in the fourth quarter of 2018 (see Note 4 – Divestitures and Assets Held for Sale of Notes to Consolidated Financial Statements).

Management's Discussion and Analysis (Continued)

Expansion Project Updates
Significant expansion project updates for the period, including projects placed into service are described below. Ongoing major expansion projects are discussed later in Company Outlook.
Northeast G&P
Susquehanna Supply Hub
During the first quarter of 2018, the remaining facilities that comprise the Susquehanna Supply Hub Expansion were fully commissioned. The project added two new compression facilities with an additional 49,000 horsepower and 59 miles of 12- to 24-inch pipeline, and increased gathering capacity, allowing a certain producer to fulfill its commitment to deliver 850 Mdth/d to our Atlantic Sunrise development.
Atlantic-Gulf
Atlantic Sunrise
In October 2018, the Atlantic Sunrise project was placed into service. This project expanded Transco's existing natural gas transmission system along with greenfield facilities to provide incremental firm transportation capacity from the northeastern Marcellus producing area to markets along Transco's mainline as far south as Station 85 in west central Alabama. We placed a portion of the mainline project facilities into service in September 2017, which increased capacity by 400 Mdth/d. We placed additional mainline facilities into service in June 2018, which increased capacity by an additional 150 Mdth/d. The full project increased Transco's capacity by 1,700 Mdth/d.
Garden State
In March 2018, Phase 2 of the Garden State Expansion project was placed into service. This project expanded Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Station 210 in New Jersey to a new interconnection on our Trenton Woodbury Lateral in New Jersey. Phase 1 of the project was placed into service in September 2017, and together Phases 1 and 2 increased capacity by 180 Mdth/d.
Commodity Prices
NGL per-unit margins were approximately 44 percent higher in the first nine months of 2018 compared to the same period of 2017 primarily due to a 28 percent increase in per-unit non-ethane prices and an approximate 22 percent decrease in per-unit natural gas feedstock prices.
NGL margins are defined as NGL revenues less any applicable Btu replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both "keep-whole" processing agreements, where we have the obligation to replace the lost heating value with natural gas, and "percent-of-liquids" agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.
The potential impact of commodity prices on our business for the remainder of 2018 is further discussed in the following Company Outlook.
Company Outlook
Our strategy is to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas and natural gas products that exists in the United States. We accomplish this by connecting the growing demand for cleaner fuels and feedstocks with our major positions in the premier natural gas and natural gas products supply basins. We continue to maintain a strong commitment to safety, environmental stewardship, operational excellence, and customer satisfaction. We believe that accomplishing these goals will position us to deliver safe and reliable service to our customers and an attractive return to our shareholders.

Management's Discussion and Analysis (Continued)

Our business plan for 2018 includes a continued focus on growing our fee-based businesses, executing growth projects and accomplishing cost discipline initiatives to ensure operations support our strategy. We anticipate operating results will increase through organic business growth driven primarily by Transco expansion projects and continued growth in the Northeast region. We intend to fund planned growth capital with retained cash flow, debt, and proceeds from asset sales.

Our updated growth capital and investment expenditures in 2018 are expected to be at least $3.9 billion. Approximately $1.8 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining growth capital spending in 2018 primarily reflects investment in gathering and processing systems in the Northeast G&P segment limited primarily to known new producer volumes, including volumes that support Transco expansion projects including our Atlantic Sunrise project, and funding for growth investment opportunities as they arise such as our investment in RMM in the West segment. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that meet legal, regulatory, and/or contractual commitments.

As a result of our significant continued capital and investment expenditures on Transco expansions and fee-based gathering and processing projects, fee-based businesses are a significant component of our portfolio and serve to reduce the influence of commodity price fluctuations on our operating results and cash flows. We expect to benefit as continued growth in demand for low-cost natural gas is driven by increases in LNG exports, industrial demand and power generation. For 2018, current forward market prices indicate oil and NGL prices are expected to be higher compared to 2017, while natural gas prices are expected to be lower as compared to 2017. We continue to address certain pricing risks through the utilization of commodity hedging strategies. However, some of our customers may continue to curtail or delay drilling plans until there is a more sustained recovery in prices, which may negatively impact our gathering and processing volumes. Reductions in drilling activity or lower energy commodity prices could also adversely affect the credit profiles of certain of our producer customers. Unfavorable changes in energy commodity prices or the credit profile of our producer customers may also result in noncash impairments of our assets.

In 2018, our operating results are expected to include increases from our regulated Transco fee-based business, primarily related to projects recently placed in-service or expected to be placed in-service in 2018 including the Atlantic Sunrise project. For our non-regulated businesses, we anticipate a reduction in fee-based revenue in the West segment, partially offset by increases in fee-based revenue in the Northeast G&P segment. As previously discussed, under the new accounting guidance for revenue recognition, deferred revenue under certain contracts will be recognized over longer periods than under the prior guidance, contributing to the decrease in annual revenue for the West region. We expect overall gathering and processing volumes to grow in 2018 and increase thereafter to meet the growing demand for natural gas and natural gas products. We also anticipate slightly lower general and administrative expenses due to the full year impact of prior year cost reduction initiatives and lower equity earnings from our investment in Discovery due to production ending on certain wells.

Potential risks and obstacles that could impact the execution of our plan include:

- Opposition to, and legal regulations affecting, our infrastructure projects, including the risk of delay or denial in permits and approvals needed for our projects;
- Unexpected significant increases in capital expenditures or delays in capital project execution;
- Counterparty credit and performance risk, including that of Chesapeake Energy Corporation and its affiliates;
- Lower than anticipated demand for natural gas and natural gas products which could result in lower than expected volumes, energy commodity prices and margins;
- General economic, financial markets, or further industry downturn, including increased interest rates;
- Physical damages to facilities, including damage to offshore facilities by named windstorms;

Management's Discussion and Analysis (Continued)

- Production issues impacting offshore gathering volumes;
- Other risks set forth under Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2017, as filed with the SEC on February 22, 2018 as supplemented by the disclosure in Part II, Item 1A. Risk Factors in this Quarterly Report on Form 10-Q.

We seek to maintain a strong financial position and liquidity, as well as manage a diversified portfolio of energy infrastructure assets which continue to serve key growth markets and supply basins in the United States.

Expansion Projects

Our ongoing major expansion projects include the following:

Northeast G&P

Ohio River Supply Hub Expansion

We agreed to expand our services for certain customers to provide additional rich gas processing capacity in the Marcellus and Upper Devonian Shale in West Virginia and Pennsylvania. Associated with these agreements, we plan to further expand the processing capacity of our Oak Grove facility by 400 MMcf/d. With one of these customers, we secured a gathering dedication agreement to gather dry gas in this same region. Additionally, we will be constructing a new NGL pipeline from Moundsville to the Harrison Hub fractionation facility to provide a new outlet for NGLs. These expansions will be supported by long-term, fee-based agreements and volumetric commitments.

Susquehanna Supply Hub Expansion

We continue to expand the gathering systems in the Susquehanna Supply Hub that are needed to meet our customers' production plans by 2020. This next expansion of the gathering infrastructure includes an additional 40,000 horsepower of new compression and gathering pipelines to bring the capacity to approximately 4.5 Bcf/d.

Atlantic-Gulf

Constitution Pipeline

We currently own 41 percent of Constitution with three other parties holding 25 percent, 24 percent, and 10 percent, respectively. We are the operator of Constitution. The 126-mile Constitution pipeline is proposed to connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York, as well as to a local distribution company serving New York and Pennsylvania.

In December 2014, Constitution received approval from the FERC to construct and operate its proposed pipeline, which will have an expected capacity of 650 Mdth/d. However, in April 2016, the New York State Department of Environmental Conservation (NYSDEC) denied the necessary water quality certification under Section 401 of the Clean Water Act for the New York portion of the pipeline. In May 2016, Constitution appealed the NYSDEC's denial of the Section 401 certification to the United States Court of Appeals for the Second Circuit and in August 2017, the court issued a decision denying in part and dismissing in part Constitution's appeal. The court expressly declined to rule on Constitution's argument that the delay in the NYSDEC's decision on Constitution's Section 401 application constitutes a waiver of the certification requirement. The court determined that it lacked jurisdiction to address that contention and found that jurisdiction over the waiver issue lies exclusively with the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). As to the denial itself, the court determined that NYSDEC's action was not arbitrary or capricious. Constitution filed a petition for rehearing with the Second Circuit Court of Appeals, but in October 2017 the court denied our petition.

In October 2017, we filed a petition for declaratory order requesting the FERC to find that, by operation of law, the Section 401 certification requirement for the New York State portion of Constitution's pipeline project was waived due to the failure by the NYSDEC to act on Constitution's Section 401 application within a reasonable period of time as required by the express terms of such statute. In January 2018, the FERC denied our petition, finding that Section 401 provides that a state waives certification only when it does not act on an application within one year from the date of the application. We filed a request for rehearing of the FERC's decision, but in July 2018 the FERC denied our request.

The project's sponsors remain committed to the project, and in September 2018 we filed a petition with the D.C. Circuit for review of the FERC's decision. (See Note 3 – Variable Interest Entities of Notes to Consolidated Financial Statements.)

Gateway

In November 2017, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from PennEast Pipeline Company's proposed interconnection with Transco's mainline south of Station 205 in New Jersey to other existing Transco meter stations within New Jersey. We plan to place the project into service in the first quarter of 2021, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 65 Mdth/d.

Gulf Connector

In November 2017, we received approval from the FERC allowing Transco to expand its existing natural gas transmission system to provide incremental firm transportation capacity from Station 65 in Louisiana to delivery points in Wharton and San Patricio Counties, Texas. We plan to place the project into service during the first quarter of 2019, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 475 Mdth/d.

Hillabee

In February 2016, the FERC issued a certificate order for the initial phases of Transco's Hillabee Expansion Project. The project involves an expansion of Transco's existing natural gas transmission system from Station 85 in west central Alabama to a new interconnection with the Sabal Trail pipeline in Alabama. The project is being constructed in phases, and all of the project expansion capacity is dedicated to Sabal Trail pursuant to a capacity lease agreement. We placed a portion of Phase I into service in June of 2017 and the remainder of Phase I into service in July of 2017. Phase I increased capacity by 818 Mdth/d. The in-service date of Phase II is planned for the second quarter of 2020, and together Phases I and II are expected to increase capacity by 1,025 Mdth/d.

In August 2017, the Court of Appeals for the District of Columbia Circuit granted an appeal of the FERC certificate order for the Southeast Market Pipelines projects (a group of related projects, including the Hillabee Expansion Project) filed by certain non-governmental organizations. In doing so, the court (i) remanded the matter to the FERC for preparation of an Environmental Impact Statement (EIS) that conforms with the court's opinion regarding quantifying certain greenhouse gas emissions, and (ii) vacated the FERC's certificate order for the projects, which would be effective following the court's mandate (by court order, the mandate will not issue until after disposition of all petitions for rehearing). In compliance with the court's directive, on February 5, 2018, the FERC issued a Final Supplemental EIS for the projects, reaffirming that while the projects would result in temporary and permanent impacts on the environment, those impacts would not be significant. On March 14, 2018, the FERC issued an order on remand reinstating the certificate and abandonment authorizations for the Hillabee Expansion Project and the other Southeast Market Pipelines projects. As this order was issued prior to the court's mandate (which was issued on March 30, 2018), we experienced no lapse in FERC authorization for the project.

Norphlet Project

In March 2016, we announced that we have reached an agreement to provide deepwater gas gathering services to the Appomattox development in the Gulf of Mexico. The project will provide offshore gas gathering services to our existing Transco lateral, which will provide transmission services onshore to our Mobile Bay processing facility. We also plan to make modifications to our Main Pass 261 Platform to install an alternate delivery route from the platform, as well as modifications to our Mobile Bay processing facility. The project is scheduled to go into service during the second quarter of 2019.

Management's Discussion and Analysis (Continued)

Northeast Supply Enhancement

In March 2017, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Station 195 in Pennsylvania to the Rockaway Delivery Lateral transfer point in New York. On April 20, 2018, the NYSDEC denied, without prejudice, Transco's application for certain permits required for the project. We addressed the technical issues identified by NYSDEC and in May 2018, we refiled our application for the permits. We plan to place the project into service in the fourth quarter of 2020, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 400 Mdth/d.

Rivervale South to Market

In August 2018, we received approval from the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from the existing Rivervale interconnection with Tennessee Gas Pipeline on Transco's North New Jersey Extension to other existing Transco locations within New Jersey. We plan to place the project into service as early as the fourth quarter of 2019, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 190 Mdth/d.

Southeastern Trail

In April 2018, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from the Pleasant Valley interconnect with Dominion's Cove Point Pipeline in Virginia to the Station 65 pooling point in Louisiana. We plan to place the project into service in late 2020, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase capacity by 296 Mdth/d.

West

North Seattle Lateral Upgrade

In July 2018, we received approval from the FERC to expand delivery capabilities on Northwest Pipeline's North Seattle Lateral. The project consists of the removal and replacement of approximately 5.9 miles of 8-inch diameter pipeline with new 20-inch diameter pipeline. We plan to place the project into service as early as the fourth quarter of 2019, assuming timely receipt of all necessary regulatory approvals. The project is expected to increase delivery capacity by approximately 159 Mdth/d.

Wamsutter Expansion

We are expanding our gathering and processing infrastructure in the Wamsutter region of Wyoming in order to meet our customers' production plans. The expansion includes the addition of approximately 54 miles of gathering pipelines and compression, and modifications to existing treating and processing facilities. We plan to place the project into service during the first quarter of 2019.

Critical Accounting Estimates

Constitution Pipeline Capitalized Project Costs

As of September 30, 2018, Property, plant, and equipment in our Consolidated Balance Sheet includes approximately $377 million of capitalized project costs for Constitution, for which we are the construction manager and own a 41 percent consolidated interest. As a result of the events discussed in Company Outlook, we evaluated the capitalized project costs for impairment as recently as December 31, 2017, and determined that no impairment was necessary. Our evaluation considered probability-weighted scenarios of undiscounted future net cash flows, including scenarios assuming construction of the pipeline, as well as a scenario where the project does not proceed. These scenarios included our most recent estimate of total construction costs. The probability-weighted scenarios also considered our assessment of the likelihood of success of the path to obtain necessary certification, as described in Company Outlook. It is reasonably possible that future unfavorable developments, such as a reduced likelihood of success, increased estimates of construction costs, or further significant delays, could result in a future impairment.

Equity-Method Investments

As of September 30, 2018, the carrying value of our equity-method investment in Discovery is $514 million. During the fourth quarter of 2017, certain customers of Discovery terminated a significant offshore gas gathering agreement following the shut-in of production after the associated wells ceased flowing. As a result, we evaluated this investment for impairment in the fourth quarter of 2017 and determined that no impairment was necessary.

This evaluation included probability-weighted assumptions of additional commercial development, assigning higher probabilities to those commercial development opportunities that were more advanced in the discussion and contracting process, that utilized existing infrastructure due to producer capital constraints, and/or that we believe Discovery has a competitive advantage due to geographical proximity to the prospect. We continue to monitor this investment as it is reasonably possible that an impairment could be required in the future if commercial development activities are not as successful or as timely as assumed.

Regulatory Liabilities Resulting from Tax Reform

In December 2017, Tax Reform was enacted, which, among other things, reduced the corporate income tax rate from 35 percent to 21 percent. Rates charged to customers of our regulated natural gas pipelines are subject to the rate-making policies of the FERC, which have historically permitted the recovery of an income tax allowance that includes a deferred income tax component. As a result of the reduced income tax rate from Tax Reform and the collection of historical rates that reflected historical federal income tax rates, we expect that our regulated natural gas pipelines will be required to return amounts to certain customers through future rates and have accordingly established regulatory liabilities totaling $657 million as of September 30, 2018. The timing and actual amount of such return will be subject to future negotiations regarding this matter and many other elements of cost–of–service rate proceedings, including other costs of providing service.

Management's Discussion and Analysis (Continued)

Results of Operations
Consolidated Overview
The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2018, compared to the three and nine months ended September 30, 2017. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2018	2017	$ Change*	% Change*	2018	2017	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues:								
Service revenues	$1,371	$1,310	+61	+5 %	$4,062	$3,853	+209	+5 %
Service revenues – commodity consideration	121	—	+121	NM	316	—	+316	NM
Product sales	811	581	+230	+40 %	2,104	1,950	+154	+8 %
Total revenues	2,303	1,891			6,482	5,803		
Costs and expenses:								
Product costs	790	504	-286	-57 %	2,039	1,620	-419	-26 %
Processing commodity expenses	30	—	-30	NM	91	—	-91	NM
Operating and maintenance expenses	389	403	+14	+3 %	1,134	1,166	+32	+3 %
Depreciation and amortization expenses	425	433	+8	+2 %	1,290	1,308	+18	+1 %
Selling, general, and administrative expenses	174	138	-36	-26 %	436	452	+16	+4 %
Gain on sale of Geismar Interest	—	(1,095)	-1,095	-100 %	—	(1,095)	-1,095	-100 %
Impairment of certain assets	—	1,210	+1,210	+100 %	66	1,236	+1,170	+95 %
Other (income) expense – net	(6)	24	+30	NM	24	34	+10	+29 %
Total costs and expenses	1,802	1,617			5,080	4,721		
Operating income (loss)	501	274			1,402	1,082		
Equity earnings (losses)	105	115	-10	-9 %	279	347	-68	-20 %
Other investing income (loss) – net	2	4	-2	-50 %	74	278	-204	-73 %
Interest expense	(270)	(267)	-3	-1 %	(818)	(818)	—	— %
Other income (expense) – net	52	23	+29	+126 %	99	124	-25	-20 %
Income (loss) before income taxes	390	149			1,036	1,013		
Provision (benefit) for income taxes	190	24	-166	NM	297	126	-171	-136 %
Net income (loss)	200	125			739	887		
Less: Net income (loss) attributable to noncontrolling interests	71	92	+21	+23 %	323	400	+77	+19 %
Net income (loss) attributable to The Williams Companies, Inc.	$129	$33			$416	$487		

* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to a change in signs, a zero-value denominator, or a percentage change greater than 200.

Management’s Discussion and Analysis (Continued)

Three months ended September 30, 2018 vs. three months ended September 30, 2017

Service revenues increased primarily due to higher transportation fee revenues at Transco associated with expansion projects placed in-service in 2017 and 2018, as well as higher gathering volumes at the Susquehanna Supply Hub.

Service revenues – commodity consideration increased as the result of implementing ASC 606 using a modified retrospective approach, effective January 1, 2018. Therefore, prior periods have not been recast under the new guidance. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. (See Note 2 – Revenue Recognition of Notes to Consolidated Financial Statements.) Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

Product sales increased primarily due to higher marketing revenues and higher sales from the production of our equity NGLs, both reflecting higher NGL prices. Higher system management gas sales, which are substantially offset in Product costs, also contributed to the increase.

The increase in Product costs is primarily due to the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services, as well as higher marketing costs and system management gas costs. This increase is partially offset by the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

Operating and maintenance expenses decreased primarily due to lower costs including reduced hydrotesting related to certain compliance projects that occurred in 2017.

Selling, general, and administrative expenses increased primarily due to a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (see Note 11 – Stockholders’ Equity of Notes to Consolidated Financial Statements) and fees associated with the WPZ Merger, partially offset by the absence of severance-related and organizational realignment costs incurred in 2017.

The unfavorable change in Gain on sale of Geismar Interest reflects the absence of the gain recognized on the sale of our Geismar Interest in July 2017 (see Note 4 – Divestitures and Assets Held for Sale of Notes to Consolidated Financial Statements.)

The favorable change in Impairment of certain assets includes the absence of 2017 impairments associated with certain assets in the Marcellus South, Mid-Continent, and Houston Ship Channel areas (see Note 12 – Fair Value Measurements and Guarantees of Notes to Consolidated Financial Statements.)

The favorable change in Other (income) expense – net within Operating income (loss) includes the benefit of establishing a regulatory asset associated with an increase in Transco’s estimated deferred state income tax rate following the WPZ Merger, partially offset by charges establishing a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger.

The favorable change in Operating income (loss) includes the absence of Impairment of certain assets incurred in 2017, and the benefit of establishing a regulatory asset associated with an increase in Transco’s estimated deferred state income tax rate following the WPZ Merger. Also included are an increase in Service revenues primarily associated with Transco projects placed in-service in 2017 and 2018, higher gathering volumes, and favorable NGL and marketing commodity margins reflecting higher NGL prices and volumes. The favorable change was partially offset by the absence of the 2017 Gain on sale of Geismar Interest and higher costs associated with our charitable contribution of preferred stock, and WPZ Merger-related fees.

The unfavorable change in Equity earnings (losses) is primarily due to a decrease in volumes at Discovery, partially offset by improved results at our Appalachia Midstream Investments.

Management's Discussion and Analysis (Continued)

The favorable change in Other income (expense) – net below Operating income (loss) is primarily due to an increase in equity funds used during construction (AFUDC). (See Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements.)

Provision (benefit) for income taxes changed unfavorably primarily due to a $105 million valuation allowance on certain deferred tax assets that may not be realized following the WPZ Merger and higher pre-tax income, partially offset by the decrease in the federal statutory rate from 35 percent to 21 percent with the enactment of Tax Reform. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rate compared to the federal statutory rate for both periods.

The favorable change in Net income (loss) attributable to noncontrolling interests is primarily due to the WPZ Merger.

Nine months ended September 30, 2018 vs. nine months ended September 30, 2017

Service revenues increased primarily due to higher transportation fee revenues at Transco primarily associated with expansion projects placed in-service in 2017 and 2018, as well as higher gathering and processing volumes across most of our operating locations. These increases were partially offset by a decrease due to a reduction of rates resulting from a Northwest Pipeline rate case settlement.

Service revenues – commodity consideration increased as the result of implementing ASC 606 using a modified retrospective approach, effective January 1, 2018. Therefore, prior periods have not been recast under the new guidance. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. (See Note 2 – Revenue Recognition of Notes to Consolidated Financial Statements.) Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

Product sales increased primarily due to higher marketing revenues and higher system management gas sales, partially offset by the absence of $268 million in olefin revenue associated with our former olefin operations in 2017. The increase in marketing revenue is driven by higher NGL prices and volumes, partially offset by lower crude oil and olefin-related volumes.

The increase in Product costs is primarily due to the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services, as well as higher marketing and system management gas costs. This increase is partially offset by the absence of $147 million of olefin feedstock volumes associated with our former olefin operations, as well as the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

Operating and maintenance expenses decreased primarily due to the absence of $52 million of costs associated with our former olefin operations, partially offset by higher operating and maintenance expenses at Transco primarily associated with general maintenance and other testing and labor costs.

Depreciation and amortization expenses decreased primarily due to the absence of costs associated with our former olefin operations, partially offset by new assets placed in-service.

Selling, general, and administrative expenses decreased primarily due to the absence of severance-related, organizational realignment, the absence of $17 million in costs associated with our former olefin operations, Financial Repositioning costs incurred in 2017, and ongoing cost containment efforts. These decreases are partially offset by a charitable contribution of preferred stock to the Williams Foundation and fees associated with the WPZ Merger.

The unfavorable change in Gain on sale of Geismar Interest reflects the absence of the gain recognized on the sale of our Geismar Interest in July 2017 (see Note 4 – Divestitures and Assets Held for Sale of Notes to Consolidated Financial Statements.)

Management's Discussion and Analysis (Continued)

The favorable change in Impairment of certain assets includes the absence of 2017 impairments associated with certain assets in the Marcellus South, Mid-Continent, and Houston Ship Channel areas, partially offset by the impairment of certain idle pipelines in 2018 (see Note 12 – Fair Value Measurements and Guarantees of Notes to Consolidated Financial Statements.)

The favorable change in Other (income) expense – net within Operating income (loss) includes the benefit of establishing a regulatory asset associated with an increase in Transco's estimated deferred state income tax rate following the WPZ Merger and favorable adjustments to certain regulatory charges associated with Tax Reform. These favorable adjustments are partially offset by the absence of gains from certain contract settlements and terminations in 2017, the absence of a gain on the sale of our RGP Splitter in 2017, and 2018 regulatory charges associated with both Northwest Pipeline's approved rates related to Tax Reform and establishing a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger.

The favorable change in Operating income (loss) includes the absence of Impairment of certain assets, an increase in Service revenues primarily associated with Transco projects placed in-service in 2017 and 2018, higher gathering and processing volumes across most of our operating locations, the benefit of establishing a regulatory asset associated with an increase in Transco's estimated deferred state income tax rate following the WPZ Merger, as well as higher NGL and marketing margins, and lower severance-related, organizational realignment, and Financial Repositioning costs. These favorable changes are partially offset by the absence of the 2017 Gain on sale of Geismar Interest, the absence of operating income related to our former olefin operations, a charitable contribution of preferred stock, 2018 regulatory charges associated with both Northwest Pipeline's approved rates related to Tax Reform and establishing a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger, and higher operating costs at Transco.

The unfavorable change in Equity earnings (losses) is primarily due to a decrease in volumes at Discovery, partially offset by improved results at our Appalachia Midstream Investments.

The unfavorable change in Other investing income (loss) – net is due to the absence of a gain on disposition of our investments in DBJV and Ranch Westex JV LLC in 2017, partially offset by a gain on the deconsolidation of our interest in Jackalope in 2018. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

The unfavorable change in Other income (expense) – net below Operating income (loss) is primarily due to the absence of a net gain on early retirement of debt in 2017 and a loss on early retirement of debt in 2018. (See Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements.) This unfavorable change is partially offset by an increase in equity AFUDC.

Provision (benefit) for income taxes changed unfavorably primarily due to the absence of releasing a $127 million valuation allowance on a capital loss carryover in 2017, a $105 million valuation allowance on certain deferred tax assets that may not be realized following the WPZ Merger, and higher pre-tax income, partially offset by the decrease in the federal statutory rate from 35 percent to 21 percent with the enactment of Tax Reform. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rate compared to the federal statutory rate for both periods.

The favorable change in Net income (loss) attributable to noncontrolling interests is primarily due to lower operating results at WPZ and the subsequent WPZ Merger.

Period-Over-Period Operating Results - Segments

We evaluate segment operating performance based upon Modified EBITDA. Note 14 – Segment Disclosures of Notes to Consolidated Financial Statements includes a reconciliation of this non-GAAP measure to Net income (loss). Management uses Modified EBITDA because it is an accepted financial indicator used by investors to compare company performance. In addition, management believes that this measure provides investors an enhanced perspective of the operating performance of our assets. Modified EBITDA should not be considered in isolation or as a substitute for a measure of performance prepared in accordance with GAAP.

Management's Discussion and Analysis (Continued)

Northeast G&P

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Service revenues	$247	$214	$707	$648
Service revenues – commodity consideration	6	—	14	—
Product sales	69	61	242	181
Segment revenues	322	275	963	829
Product costs	(69)	(61)	(245)	(179)
Processing commodity expenses	(3)	—	(7)	—
Other segment costs and expenses	(100)	(98)	(279)	(273)
Impairment of certain assets	—	(121)	—	(123)
Proportional Modified EBITDA of equity-method investments	131	120	354	334
Northeast G&P Modified EBITDA	$281	$115	$786	$588

Three months ended September 30, 2018 vs. three months ended September 30, 2017

Modified EBITDA increased primarily due to the absence of Impairment of certain assets in 2018 and higher Service revenues.

Service revenues increased primarily due to higher gathering volumes at Susquehanna Supply Hub reflecting increased production from customers.

Product sales increased primarily due to higher system management gas sales. System management gas sales are offset in Product costs and therefore have little impact to Modified EBITDA.

Impairment of certain assets changed favorably primarily due to the absence of a $115 million impairment of certain gathering operations in the Marcellus South region and $6 million of write-downs of certain assets that were no longer in use or were surplus in nature in the third quarter of 2017.

Proportional Modified EBITDA of equity-method investments increased primarily due to a $7 million increase at Appalachia Midstream Investments reflecting higher volumes.

Nine months ended September 30, 2018 vs. nine months ended September 30, 2017

Modified EBITDA increased primarily due to the absence of Impairment of certain assets in 2018 and higher Service revenues.

Service revenues increased primarily due to higher gathering volumes at Susquehanna Supply Hub reflecting increased production from customers, as well as higher gathering revenues and higher fractionation revenues at Ohio Valley Midstream, and higher compression revenue in the Marcellus South region.

Service revenues – commodity consideration increased as a result of implementing ASC 606 using a modified retrospective approach. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. Most of these NGL volumes are sold within the month processed and therefore are offset in Processing commodity expenses below.

Product sales increased primarily due to $42 million in higher marketing sales, driven by higher non-ethane prices and volumes. The changes in marketing revenues are offset by similar changes in marketing purchases, reflected above as Product costs. The increase in Product sales also includes $16 million in higher system management gas sales. System management gas sales are offset in Product costs and therefore have little impact on Modified EBITDA.

Management's Discussion and Analysis (Continued)

Impairment of certain assets changed favorably primarily due to the absence of a $115 million impairment of certain gathering operations in the Marcellus South region.

Proportional Modified EBITDA of equity-method investments increased primarily due to a $26 million increase at Appalachia Midstream Investments reflecting our increased ownership acquired in late first-quarter 2017 and higher volumes.

Atlantic-Gulf

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Service revenues	$607	$564	$1,806	$1,647
Service revenues – commodity consideration	18	—	45	—
Product sales	131	106	329	365
Segment revenues	756	670	2,180	2,012
Product costs	(134)	(97)	(332)	(328)
Processing commodity expenses	(3)	—	(10)	—
Other segment costs and expenses	(176)	(207)	(556)	(566)
Proportional Modified EBITDA of equity-method investments	49	64	136	216
Atlantic-Gulf Modified EBITDA	$492	$430	$1,418	$1,334
NGL margin	$12	$7	$30	$30

Three months ended September 30, 2018 vs. three months ended September 30, 2017

Modified EBITDA increased primarily due to higher Service revenues and lower Other segment costs and expenses, partially offset by lower Proportional Modified EBITDA of equity-method investments.

Service revenues increased primarily due to a $34 million increase in Transco's natural gas transportation fee revenues driven by expansion projects placed in service in 2017 and 2018.

Service revenues – commodity consideration increased as a result of implementing ASC 606 using a modified retrospective approach. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

The increase in Product sales includes:

- A $20 million increase in system management gas sales. System management gas sales are offset in Product costs and therefore have little impact to Modified EBITDA;
- A $1 million increase in commodity marketing revenues driven by a $30 million increase in NGL marketing revenues reflecting 38 percent higher non-ethane prices and a 24 percent increase in non-ethane volumes, partially offset by a $29 million decrease in crude oil revenues as this activity is now presented on a net basis within Product costs in 2018 in conjunction with the adoption of ASC 606.

Product costs increased primarily due to a $21 million increase in system management gas costs (offset in Product sales) and the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services. This increase was partially offset by the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

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Management's Discussion and Analysis (Continued)

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

The net sum of Service revenues – commodity consideration, Product sales, Product costs, and Processing commodity expenses comprise our commodity product margins.

Other segment costs and expenses decreased primarily due to a $16 million increase in Transco's equity AFUDC and lower operating and maintenance costs including reduced hydrotesting related to certain compliance projects that occurred in 2017.

The decrease in Proportional Modified EBITDA of equity-method investments is due to an $18 million decrease at Discovery, primarily associated with production ending on certain wells.

Nine months ended September 30, 2018 vs. nine months ended September 30, 2017

Modified EBITDA increased primarily due to higher Service revenues, partially offset by lower Proportional Modified EBITDA of equity-method investments.

Service revenues increased primarily due to a $148 million increase in Transco's natural gas transportation fee revenues driven by a $133 million increase associated with expansion projects placed in service in 2017 and 2018.

Service revenues – commodity consideration increased as a result of implementing ASC 606 using a modified retrospective approach. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

The decrease in Product sales includes:

- A $62 million decrease in commodity marketing revenues driven by a $119 million decrease in crude oil revenues as this activity is now presented on a net basis within Product costs in 2018 in conjunction with the adoption of ASC 606, partially offset by a $57 million increase in NGL marketing revenues reflecting 38 percent higher non-ethane prices and a 10 percent increase in non-ethane volumes;
- A $43 million increase in system management gas sales. System management gas sales are offset in Product costs and therefore have little impact to Modified EBITDA.

Product costs increased primarily due to a $44 million increase in system management gas costs (offset in Product sales) and the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services. This increase was partially offset by a $59 million decrease in marketing purchases (more than offset in Product sales) and the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

The net sum of Service revenues – commodity consideration, Product sales, Product costs, and Processing commodity expenses comprise our commodity product margins.

Other segment costs and expenses decreased primarily due to a $25 million increase in Transco's equity AFUDC and a net favorable adjustment to deferred–tax related regulatory liabilities associated with Tax Reform. These decreases are partially offset by higher operating and maintenance expense driven by a $15 million increase primarily associated with general maintenance and other testing and labor costs.

The decrease in Proportional Modified EBITDA of equity-method investments is due to an $81 million decrease at Discovery, primarily related to a $71 million decrease associated with production ending on certain wells.

Management’s Discussion and Analysis (Continued)

West

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Service revenues	$533	$544	$1,599	$1,589
Service revenues – commodity consideration	97	—	257	—
Product sales	732	485	1,822	1,376
Segment revenues	1,362	1,029	3,678	2,965
Product costs	(730)	(438)	(1,813)	(1,263)
Processing commodity expenses	(26)	—	(76)	—
Other segment costs and expenses	(219)	(203)	(637)	(615)
Impairment of certain assets	—	(1,021)	—	(1,022)
Proportional modified EBITDA of equity-method investments	25	18	62	61
West Modified EBITDA	$412	$(615)	$1,214	$126
NGL margin	$60	$37	$165	$104

Three months ended September 30, 2018 vs. three months ended September 30, 2017

Modified EBITDA increased primarily due to the absence of Impairment of certain assets in 2017 and higher commodity margins associated with our equity NGLs.

Service revenues decreased primarily due to:

- A $12 million decrease related to the deconsolidation of Jackalope in second quarter 2018;
- An $8 million decrease related to lower gathering volumes primarily in the Eagle Ford and Haynesville Shale regions;
- A $6 million decrease at Northwest Pipeline primarily due to the reduction of its rates as a result of a rate case settlement that became effective January 1, 2018;
- Offsetting changes primarily associated with implementing the new revenue guidance under ASC 606 including a $30 million decrease related to lower amortization of deferred revenue associated with the up-front cash payments received in conjunction with the fourth quarter 2016 Barnett Shale and Mid-Continent contract restructurings, offset by a $15 million increase related to the earlier recognition of revenues associated with MVCs and a $15 million increase related to other deferred revenue amortization primarily in the Permian basin;
- A $9 million increase related to higher gathering and processing rates driven by higher NGL prices primarily in the Piceance region.

Service revenues – commodity consideration increased as a result of implementing ASC 606 using a modified retrospective approach. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

The increase in Product sales includes:

- A $207 million increase in marketing revenues primarily due to increases in realized product prices and volumes including a 29 percent increase in average non-ethane per-unit sales prices and a 41 percent increase in ethane prices, in addition to a 20 percent increase in NGL volumes (offset by higher Product costs);

Management's Discussion and Analysis (Continued)

- A $11 million increase in system management gas sales due to a change in presentation in accordance with ASC 606, which are offset in Product costs and, therefore, have no impact on Modified EBITDA.

The increase in Product costs includes the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services, as well as a $208 million increase in marketing purchases (offset in Product sales). The increase also includes a $12 million increase in system management gas costs (substantially offset in Product sales), partially offset by the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

The net sum of Service revenues – commodity consideration, Product sales, Product costs, and Processing commodity expenses comprise our commodity product margins. Our commodity product margins increased primarily due to a $23 million increase in NGL product margins driven by $16 million in higher non-ethane margins, reflecting 19 percent higher realized non-ethane prices and 20 percent lower realized natural gas prices.

Other segment costs and expenses increased primarily due to a $12 million charge for a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger.

Impairment of certain assets decreased primarily due to the absence of a $1.019 billion impairment of certain gathering operations in the Mid-Continent region in 2017.

Proportional modified EBITDA of equity-method investments increased primarily due to the deconsolidation of Jackalope in the second quarter of 2018, such that we now use the equity method of accounting for this investment.

Nine months ended September 30, 2018 vs. nine months ended September 30, 2017

Modified EBITDA increased primarily due to the absence of Impairment of certain assets in 2017 and higher commodity margins driven by an increase in equity NGL margins, partially offset by higher Other segment costs and expenses.

Service revenues increased primarily due to:

- A $23 million increase associated with an increase in gathering and processing rates driven by higher NGL prices primarily in the Piceance region as well as higher average gathering and processing rates across most other areas, partially offset by declining contract rates primarily in the Haynesville Shale region;
- A $17 million increase driven by higher gathering volumes primarily in the Haynesville Shale, Piceance, Niobrara, and Permian regions, partially offset by lower volumes in the Eagle Ford and Barnett Shale regions;
- Offsetting changes primarily associated with implementing the new revenue guidance under ASC 606 including an $89 million decrease related to lower amortization of deferred revenue associated with the up-front cash payments received in conjunction with the fourth quarter 2016 Barnett Shale and Mid-Continent contract restructurings, offset by a $49 million increase related to the earlier recognition of revenues associated with MVCs and a $40 million increase related to other deferred revenue amortization primarily in the Permian basin;
- A $22 million decrease at Northwest Pipeline primarily due to the reduction of its rates as a result of a rate case settlement that became effective January 1, 2018;
- A $12 million decrease related to the Jackalope deconsolidation in second quarter 2018.

Management's Discussion and Analysis (Continued)

Service revenues – commodity consideration increased as a result of implementing ASC 606 using a modified retrospective approach. These revenues represent consideration we receive in the form of commodities as full or partial payment for gathering and processing services provided. Most of these NGL volumes are sold within the month processed and therefore are offset in Product costs below.

The increase in Product sales includes:

- A $336 million increase in marketing revenues primarily due to increases in realized NGL prices including a 29 percent increase in average non-ethane per-unit sales prices and a 23 percent increase in ethane prices, in addition to a 19 percent increase in ethane volumes (substantially offset by higher Product costs);
- A $36 million increase in system management gas sales due to a change in presentation in accordance with ASC 606, which are offset in Product costs and, therefore, have no impact on Modified EBITDA.

The increase in Product costs includes the impact of ASC 606 in which costs reflected in this line item for 2018 include volumes acquired as commodity consideration for NGL processing services, a $323 million increase in marketing purchases (more than offset in Product sales), a $38 million increase in system management gas costs (substantially offset in Product sales), partially offset by the absence of natural gas purchases associated with the production of equity NGLs, which are now reported in Processing commodity expenses in conjunction with the implementation of ASC 606.

Processing commodity expenses presents the natural gas purchases associated with the production of equity NGLs as previously described in conjunction with the implementation of ASC 606.

The net sum of Service revenues – commodity consideration, Product sales, Product costs, and Processing commodity expenses comprise our commodity product margins. Our commodity product margins increased primarily due to a $61 million increase in NGL product margins and a $13 million increase in marketing margins. NGL margins are driven by $52 million in higher non-ethane margins, reflecting 19 percent higher realized non-ethane prices and 25 percent lower realized natural gas prices.

Other segment costs and expenses increased primarily due to an $18 million regulatory charge associated with Northwest Pipeline's approved rates related to Tax Reform, the absence of a $15 million gain from contract settlements and terminations in 2017, and a $12 million charge for a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger, partially offset by $20 million lower operating and maintenance and general and administrative costs reflecting ongoing cost containment efforts.

Impairment of certain assets decreased primarily due to the absence of a $1.019 billion impairment of certain gathering operations in the Mid-Continent region in 2017.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(Millions)			
Other Modified EBITDA	$6	$1,009	$(49)	$1,100

Three months ended September 30, 2018 vs. three months ended September 30, 2017

Modified EBITDA decreased primarily due to:

- The absence of a $1.095 billion gain on the sale of our Geismar Interest in 2017;
- A $35 million charge associated with a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (a not-for-profit corporation) (see Note 11 – Stockholders' Equity of Notes to Consolidated Financial Statements);

Management's Discussion and Analysis (Continued)

- $15 million in costs associated with the WPZ Merger.

These decreases were partially offset by:

- The absence of a $68 million impairment for a certain NGL pipeline asset in the third quarter of 2017;
- A $37 million increase associated with the benefit of establishing a regulatory asset associated with an increase in Transco's estimated deferred state income tax rate following the WPZ Merger;
- A $14 million increase in income associated with a regulatory asset related to deferred taxes on equity funds used during construction;
- The absence of $10 million of severance-related and strategic alternative costs in 2017;
- The absence of $8 million of costs in 2017 associated with our former Geismar olefins plant.

Nine Months Ended September 30, 2018 vs. nine months ended September 30, 2017

Modified EBITDA decreased primarily due to:

- The absence of a $1.095 billion gain on the sale of our Geismar Interest in 2017;
- The absence of $70 million of Modified EBTIDA associated with the olefin operations that were sold in 2017;
- A $35 million charge associated with a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (a not-for-profit corporation) (see Note 11 – Stockholders' Equity of Notes to Consolidated Financial Statements);
- A $34 million decrease due to the absence of a net gain on early retirement of debt in 2017 and a loss on early retirement of debt in 2018 (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- $19 million in costs associated with the WPZ Merger (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- A $13 million decrease in income associated with a regulatory asset related to deferred taxes on equity funds used during construction;
- The absence of a $12 million gain on the sale of the Refinery Grade Propylene Splitter in 2017 (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements).

These decreases were partially offset by:

- The absence of a $68 million impairment for a certain NGL pipeline asset in the third quarter of 2017 and a$23 million impairment of an olefins pipeline project in the Gulf Coast region in the second quarter of 2017, partially offset by a $66 million impairment of certain idle pipelines in the second quarter of 2018 (see Note 12 – Fair Value Measurements and Guarantees of Notes to Consolidated Financial Statements);
- A $37 million increase associated with the benefit of establishing a regulatory asset associated with an increase in Transco's estimated deferred state income tax rate following the WPZ Merger;
- $37 million of lower costs, driven by the absence of expenses associated with severance and related costs, Financial Repositioning, and strategic alternative costs (see Note 1 – General, Description of Business, and Basis of Presentation of Notes to Consolidated Financial Statements).

Management's Discussion and Analysis (Continued)

Management's Discussion and Analysis of Financial Condition and Liquidity

Outlook

Fee-based businesses are a significant component of our portfolio and serve to reduce the influence of commodity price fluctuations on our cash flows. We expect to benefit as continued growth in demand for low-cost natural gas is driven by increases in LNG exports, industrial demand, and power generation.

As previously discussed in Company Outlook, our consolidated growth capital and investment expenditures in 2018 are currently expected to be at least $3.9 billion. Approximately $1.8 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining growth capital spending in 2018 primarily reflects investment in gathering and processing systems in the Northeast G&P segment limited primarily to known new producer volumes, including volumes that support Transco expansion projects including our Atlantic Sunrise project, and funding for growth investment opportunities as they arise such as our investment in RMM in the West segment. In addition to growth capital and investment expenditures, we also remain committed to projects that maintain our assets for safe and reliable operations, as well as projects that meet legal, regulatory, and/or contractual commitments. We intend to fund the planned 2018 growth capital with retained cash flow, debt, and proceeds from asset sales. We retain the flexibility to adjust planned levels of growth capital and investment expenditures in response to changes in economic conditions or business opportunities.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2018. Our potential material internal and external sources and uses of consolidated liquidity for 2018 are as follows:

Sources:

- Cash and cash equivalents on hand
- Cash generated from operations
- Distributions from our equity-method investees
- Utilization of our credit facility and/or commercial paper program
- Cash proceeds from issuance of debt and/or equity securities
- Proceeds from asset monetizations

Uses:

- Working capital requirements
- Capital and investment expenditures
- Quarterly dividends to our shareholders
- Debt service payments, including payments of long-term debt

Potential risks associated with our planned levels of liquidity discussed above include those previously discussed in Company Outlook.

As of September 30, 2018, we had a working capital deficit of $777 million. Our available liquidity is as follows:

Available Liquidity	September 30, 2018
	(Millions)
Cash and cash equivalents	$ 42
Capacity available under our $4.5 billion credit facility, less amounts outstanding under our $4 billion commercial paper program (1)	3,676
	$ 3,718

(1) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program. Through completion of the WPZ Merger on August 10, 2018, the highest combined amount outstanding under WPZ's commercial paper program and credit facility and our former credit facility during 2018 was $1.325 billion. In July 2018, we along with Transco and Northwest Pipeline entered into a new unsecured revolving credit agreement with aggregate commitments available of $4.5 billion under the credit facility, which became effective upon completion of the WPZ Merger. Through September 30, 2018, the highest amount outstanding under our current commercial paper program and credit facility during 2018 was $886 million. At September 30, 2018, we were in compliance with the financial covenants associated with our credit facility. Borrowing capacity available under our credit facility as of October 30, 2018, was $4.5 billion.

Dividends

We increased our regular quarterly cash dividend by approximately 13 percent from the previous quarterly cash dividends of $0.30 per share paid in each quarter of 2017, to $0.34 per share for the quarterly cash dividends paid in March, June, and September 2018.

Registrations

In February 2018, we filed a shelf registration statement, as a well-known seasoned issuer. In August 2018, we filed a prospectus supplement for the offer and sale from time to time of shares of our common stock having an aggregate offering price of up to $1 billion. These sales are to be made over a period of time and from time to time in transactions at then-current prices. Such sales are to be made pursuant to an equity distribution agreement between us and certain entities who may act as sales agents or purchase for their own accounts as principals at a price agreed upon at the time of the sale.

In February 2018, WPZ filed a shelf registration statement, as a well-known seasoned issuer, registering common units representing limited partner interests and debt securities. Also in February 2018, WPZ filed a shelf registration statement for the offer and sale from time to time of common units representing limited partner interests in WPZ having an aggregate offering price of up to $1 billion. In August 2018, these registration statements were terminated in conjunction with the WPZ Merger.

In September 2016, WPZ filed a registration statement for its distribution reinvestment program. In August 2018, this registration statement was terminated in conjunction with the WPZ Merger.

Distributions from Equity-Method Investees

The organizational documents of entities in which we have an equity-method investment generally require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses.

Management's Discussion and Analysis (Continued)

Credit Ratings
Our ability to borrow money is impacted by our credit ratings. The current ratings are as follows:

Rating Agency	Outlook	Senior Unsecured Debt Rating	Corporate Credit Rating
S&P Global Ratings	Negative	BBB	BBB
Moody's Investors Service	Stable	Baa3	N/A
Fitch Ratings	Positive	BBB-	N/A

Following the completion of the WPZ Merger, in August 2018, all three credit rating agencies upgraded the ratings as noted in the table above.
These credit ratings are included for informational purposes and are not recommendations to buy, sell, or hold our securities, and each rating should be evaluated independently of any other rating. No assurance can be given that the credit rating agencies will continue to assign us investment-grade ratings even if we meet or exceed their current criteria for investment-grade ratios. A downgrade of our credit ratings might increase our future cost of borrowing and would require us to provide additional collateral to third parties, negatively impacting our available liquidity.
Sources (Uses) of Cash
The following table summarizes the sources (uses) of cash and cash equivalents for each of the periods presented (see Notes to Consolidated Financial Statements for the Notes referenced in the table):

	Cash Flow Category	Nine Months Ended September 30, 2018	2017
		(Millions)	
Sources of cash and cash equivalents:			
Operating activities – net	Operating	$2,331	$2,231
Proceeds from long-term debt (see Note 10)	Financing	2,065	1,698
Proceeds from credit-facility borrowings	Financing	1,680	1,315
Proceeds from commercial paper – net	Financing	821	—
Contributions in aid of construction	Investing	395	253
Proceeds from equity issuances	Financing	15	2,130
Proceeds from sale of businesses, net of cash divested (see Note 4)	Investing	—	2,056
Proceeds from dispositions of equity-method investments (see Note 5)	Investing	—	200
Uses of cash and cash equivalents:			
Capital expenditures	Investing	(2,659)	(1,700)
Payments on credit-facility borrowings	Financing	(1,950)	(1,690)
Payments of long-term debt (see Note 10)	Financing	(1,251)	(3,785)
Common dividends paid	Financing	(974)	(744)
Purchases of and contributions to equity-method investments	Investing	(803)	(103)
Dividends and distributions paid to noncontrolling interests	Financing	(552)	(636)
Payments of commercial paper – net	Financing	—	(93)
Other sources / (uses) – net	Financing and Investing	25	(130)
Increase (decrease) in cash and cash equivalents		$(857)	$1,002

Operating activities

The factors that determine operating activities are largely the same as those that affect Net income (loss), with the exception of noncash items such as Depreciation and amortization, Provision (benefit) for deferred income taxes, Equity (earnings) losses, Net (gain) loss on disposition of equity-method investments, Gain on sale of Geismar Interest, and Impairment of and net (gain) loss on sale of assets. Our Net cash provided (used) by operating activities for the nine months ended September 30, 2018, increased from the same period in 2017 primarily due to higher operating income in 2018, partially offset by the impact of net unfavorable changes in operating working capital and decreased distributions from unconsolidated affiliates in 2018.

Off-Balance Sheet Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Note 3 – Variable Interest Entities, Note 10 – Debt and Banking Arrangements, Note 12 – Fair Value Measurements and Guarantees, and Note 13 – Contingent Liabilities of Notes to Consolidated Financial Statements. We do not believe these guarantees and commitments or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Item 3
Quantitative and Qualitative Disclosures About Market Risk
Interest Rate Risk
Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first nine months of 2018.

Item 4
Controls and Procedures
Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act of 1934, as amended) (Disclosure Controls) or our internal control over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.
Evaluation of Disclosure Controls and Procedures
An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.
Changes in Internal Control Over Financial Reporting
There have been no changes during the third quarter of 2018 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
Environmental
Certain reportable legal proceedings involving governmental authorities under federal, state, and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings which are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings.

On June 13, 2013, an explosion and fire occurred at our formerly owned Geismar olefins plant and rendered the facility temporarily inoperable (Geismar Incident). On October 21, 2013, the EPA, Region 6, issued an Inspection Report pursuant to the Clean Air Act's Risk Management Program following its inspection of the facility on June 24 through June 28, 2013. The report notes the EPA's preliminary determinations about the facility's documentation regarding process safety, process hazard analysis, as well as operating procedures, employee training, and other matters. On June 16, 2014, we received a request for information related to the Geismar Incident from the EPA under Section 114 of the Clean Air Act to which we responded on August 13, 2014. The EPA could issue penalties pertaining to final determinations.

On February 21, 2017, we received notice from the Environmental Enforcement Section of the United States Department of Justice (DOJ) regarding certain alleged violations of the Clean Air Act at our Moundsville facility as set forth in a Notice of Noncompliance issued by the EPA on January 14, 2016. The notice includes an offer to avoid further legal action on the alleged violations by paying $2 million. In discussion with the DOJ and the EPA, the EPA has indicated its belief that additional similar violations have occurred at our Oak Grove facility and has expressed interest in pursuing a global settlement. On July 23, 2018, we received an offer from the DOJ to globally settle the government's claim for civil penalties associated with the alleged violations at both the Moundsville and the Oak Grove facilities for $1.6 million. We are evaluating the agencies' offer.

On May 5, 2017, we entered into a Consent Order with the Georgia Department of Natural Resources, Environmental Protection Division (GADNR) pertaining to alleged violations of the Georgia Water Quality Control Act and associated rules arising from a permit issued by GADNR for construction of the Dalton Project. Pursuant to the Consent Order, we paid a fine of $168,750 and agreed to perform a Corrective Action Plan, the completion of which is pending.

On January 19, 2018, we received notice from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding certain alleged violations of PHMSA regulations in connection with a fire and release of liquid ethane that occurred at our Houston Meter Station located near Houston, Washington County, Pennsylvania, on December 24, 2014. The Notice of Probable Violation and Proposed Civil Penalty issued by PHMSA alleges failure to timely notify the National Response Center of a release of a hazardous liquid resulting in a fire or explosion and failure to verify that the facility was constructed, inspected, tested, and calibrated in accordance with comprehensive written specifications or standards and proposes a total civil penalty of $174,100. We have since paid the proposed civil penalty and have resolved this matter.

On March 19, 2018, we received a Notice of Violation from the EPA, Region 8, regarding certain alleged violations of the Clean Air Act at our Ignacio Gas Plant in Durango, Colorado, following a previous on-site inspection of the facility. We were subsequently informed that this matter has been referred to the DOJ for handling. The Notice of Violation does not contain an initial penalty assessment. We have responded to the alleged violations and continue to work with the agencies to resolve this matter.

On March 20, 2018, we also received a Notice of Violation from the EPA, Region 8, regarding certain alleged violations of the Clean Air Act at our Parachute Creek Gas Plant in Parachute, Colorado, following a previous on-site inspection of the facility. We were informed that this matter has been referred to the DOJ for handling. The Notice of Violation does not contain an initial penalty assessment. We have responded to the alleged violations and continue to work with the agencies to resolve this matter.

Other environmental matters called for by this Item are described under the caption "Environmental Matters" in Note 13 – Contingent Liabilities of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this Item.

Other Litigation

The additional information called for by this Item is provided in Note 13 – Contingent Liabilities of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this Item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2017 and Part II, Item 1A. Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, include risk factors that could materially affect our business, financial condition, or future results. Those risk factors have not materially changed, except, as stated below:

The following risk factor is now applicable:

A current ballot measure in Colorado may adversely impact our financial condition and results of operations if passed.

On November 6, 2018, citizens of Colorado will vote on Proposition 112, a ballot measure that could significantly increase setback distances from occupied structures or other vulnerable areas, as defined or designated, for any new oil and gas development in the state, critically restricting or banning such activities. If the measure is approved, it could still be subject to modification or amendment by the Colorado legislature. An unfavorable outcome could adversely impact the operations, and ultimately the value, of our businesses and investments in Colorado, including our recent investment in RMM. Any such impact may have an adverse effect on our business, financial condition, results of operations and our cash flows.

With the August 10, 2018 consummation of the WPZ Merger, certain risk factors, identified by the captions stated below, are no longer applicable:

Our cash flow is heavily dependent on the earnings and distributions of WPZ.

One of our subsidiaries acts as the general partner of a publicly traded limited partnership, Williams Partners L.P. As such, this subsidiary's operations may involve a greater risk of liability than ordinary business operations.

Our ability to obtain credit in the future could be affected by WPZ's credit ratings.

The FERC recently issued a policy statement that reversed its 2005 income tax policy that permitted master limited partnership (MLP) interstate oil and natural gas pipelines to recover an income tax allowance in cost of service rates, which if implemented, may adversely impact our financial condition and future results of operations.

The WPZ Merger is subject to closing conditions that, if not satisfied or waived, will result in the WPZ Merger not being consummated, which may cause the market price of our common stock and/or the WPZ Units to decline.

The WPZ Merger Agreement contains provisions that limit our ability to pursue alternatives to the WPZ Merger, could discourage a potential competing acquirer of us from making a favorable alternative acquisition proposal and, in specified circumstances under the WPZ Merger Agreement, require us to pay a termination fee of $410 million to Williams Partners.

If the Charter Amendment is approved, we will be able to issue more shares of Williams common stock than are expected to be outstanding immediately after the WPZ Merger is completed. Any future issuances of our common stock may have a dilutive effect on the earnings per share and voting power of our stockholders.

Item 6. Exhibits

Exhibit No.		Description
2.1+	—	Agreement and Plan of Merger dated as of May 16, 2018, by and among The Williams Companies, Inc., SCMS LLC, Williams Partners L.P., and WPZ GP LLC (filed on May 17, 2018 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.2	—	Amendment No 1. to Agreement and Plan of Merger dated as of May 1, 2016, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC and Energy Transfer Equity GP, LLC (filed on May 3, 2016 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.3+	—	Agreement and Plan of Merger dated as of September 28, 2015, by and among The Williams Companies, Inc., Energy Transfer Corp LP, Energy Transfer Corp GP, LLC, Energy Transfer Equity, L.P., LE GP, LLC and Energy Transfer Equity GP, LLC (filed on October 1, 2015 as Exhibit 2.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
2.4+	—	Membership Interest Purchase Agreement, dated as of April 13, 2017, among Williams Field Services Group, LLC, Williams Partners L.P., Williams Olefins, L.L.C., NOVA Chemicals Inc., and NOVA Chemicals Corporation (filed on August 3, 2017 as Exhibit 2.2 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-34831) and incorporated herein by reference).
3.1	—	Amended and Restated Certificate of Incorporation as supplemented (filed on May 26, 2010, as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.2	—	Certificate of Designations of Series B Preferred Stock of The Williams Companies, Inc. (filed on July 17, 2018 as Exhibit 3.1 to The Williams Companies, Inc. current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.3	—	Certificate of Amendment dated August 10, 2018 (filed on August 10, 2018 as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
3.4	—	By-Laws (filed on January 20, 2017, as Exhibit 3.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.1	—	Eleventh Supplemental Indenture, dated as of August 10, 2018, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on August 10, 2018 as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
4.2	—	Second Supplemental Indenture, dated as of August 10, 2018, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on August 10, 2018 as Exhibit 4.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.1	—	Credit Agreement dated as of July 13, 2018, between The Williams Companies, Inc., Northwest Pipeline LLC, and Transcontinental Gas Pipeline Company, LLC, as co-borrowers, the lenders named therein, and Citibank, N.A. as Administrative Agent (filed on July 17, 2018 as Exhibit 10.1 to The Williams Companies, Inc.'s Current Report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.2	—	Form of Commercial Paper Dealer Agreement, dated as of August 10, 2018, between The Williams Companies, Inc., as Issuer, and the Dealer party thereto (filed on August 10, 2018 as Exhibit 10.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.	Description
31.1*	— Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	— Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32**	— Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	— XBRL Instance Document.
101.SCH*	— XBRL Taxonomy Extension Schema.
101.CAL*	— XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	— XBRL Taxonomy Extension Definition Linkbase.
101.LAB*	— XBRL Taxonomy Extension Label Linkbase.
101.PRE*	— XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

** Furnished herewith.

+ Pursuant to item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE WILLIAMS COMPANIES, INC.
(Registrant)

/s/ TED T. TIMMERMANS
Ted T. Timmermans
Vice President, Controller and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)
November 1, 2018