WILLIAMS COMPANIES INC
Form 10-K
February 21, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
¨ 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)	(IRS Employer Identification No.)
One Williams Center, Tulsa, Oklahoma	74172
(Address of Principal Executive Offices)	(Zip Code)

918-573-2000
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
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 ¨

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

Exchange Act. ¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second quarter was approximately $21,489,112,717.

The number of shares outstanding of the registrant's common stock outstanding at February 15, 2019 was 1,210,981,263.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for the Registrant's Annual Meeting of Stockholders to be held on May 9, 2019, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.
FORM 10-K

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DEFINITIONS

The following is a listing of certain abbreviations, acronyms and other industry terminology that may be used throughout this Annual Report.

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 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 December 31, 2018, we account for as an equity-method investment, including principally the following:

Aux Sable: Aux Sable Liquid Products LP
Brazos Permian II: Brazos Permian II, LLC
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
Exchange Act, the: Securities and Exchange Act of 1934, as amended
FERC: Federal Energy Regulatory Commission
GAAP: Generally accepted accounting principles
IRS: Internal Revenue Service
SEC: Securities and Exchange Commission
Other:
ACMP: Access Midstream Partners, L.P. prior to its 2015 merger with Pre-Merger WPZ
Energy Transfer: Energy Transfer Equity, L.P.
ETC: Energy Transfer Corp LP
ETC Merger: Merger wherein Williams would have been merged into ETC
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 its constituent products, such as ethane, propane, and butane
Geismar Incident: An explosion and fire which occurred on June 13, 2013, at our formerly owned Geismar olefins plant and rendered the facility temporarily inoperable.
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 Btu replacement cost, plant fuel, transportation, and fractionation
Pre-merger WPZ: Williams Partners L.P. prior to its merger with ACMP
PDH facility: Propane dehydrogenation facility
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.

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may 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 a words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Additional information regarding forward-looking statements and important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A in this Annual Report.

PART I

Item 1. Business

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise indicates, all of our subsidiaries) is at times referred to in the first person as “we,” “us” or “our.” We also sometimes refer to Williams as the “Company.”

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the SEC under the Exchange Act.

Our Internet website is http://investor.williams.com/. We make available, free of charge, through the Investors tab of our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, information regarding corporate social responsibility, Code of Ethics for Senior Officers, Board committee charters, and the Williams Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Corporate Secretary, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are an energy infrastructure company focused on connecting North America’s significant hydrocarbon resource plays to markets for natural gas and NGLs. Our operations are located in the United States.

We were founded in 1908, originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. Williams’ headquarters are located in Tulsa, Oklahoma, with other major offices in Salt Lake City, Utah; Houston, Texas; and Pittsburgh, Pennsylvania. Our telephone number is 918-573-2000.

WPZ MERGER

On August 10, 2018, we completed our merger with Williams Partners L.P. (WPZ), our previously consolidated master limited partnership, 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 noncash equity transaction.

BUSINESS SEGMENTS

Prior to our merger with WPZ, 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 4 – Variable Interest Entities of Notes to Consolidated Financial Statements).
- West is comprised of our interstate natural gas pipeline, Northwest Pipeline, and our gathering, processing, and treating operations in Colorado, Wyoming, and 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 50 percent equity-method investment in RMM, a 15 percent equity-method investment in Brazos Permian II, and our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 6 – Investing Activities of Notes to Consolidated Financial Statements). West also included our former natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).
- Other includes our previously owned operations, including an 88.5 percent undivided interest in an olefins production facility in Geismar, Louisiana, which was sold in July 2017 (see Note 3 – Divestitures of Notes to Consolidated Financial Statements), and a refinery grade propylene splitter in the Gulf region, which was sold in June 2017. This segment also included our previously owned Canadian assets, which included an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility at Redwater, Alberta. In September 2016, these Canadian operations were sold. Other also includes minor business activities that are not operating segments, as well as corporate operations.

Detailed discussion of each of our reporting segments follows. For a discussion of our ongoing expansion projects, see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Northeast G&P

This segment includes our natural gas gathering, compression, processing, and NGL fractionation business in the Marcellus and Utica Shale regions in Pennsylvania, West Virginia, New York, and Ohio.

The following tables summarize the significant consolidated assets of this segment:

Natural Gas Gathering Assets

	Location	Pipeline Miles	Inlet Capacity (Bcf/d)	Ownership Interest	Supply Basins
Ohio Valley Midstream	Ohio, West Virginia, & Pennsylvania	216	0.8	100%	Appalachian
Susquehanna Supply Hub	Pennsylvania & New York	454	3.6	100%	Appalachian
Cardinal (1)	Ohio	360	0.9	66%	Appalachian
Flint	Ohio	75	0.5	100%	Appalachian
Beaver Creek	Pennsylvania	41	0.1	100%	Appalachian

(1) Statistics reflect 100 percent of the assets from our 66 percent ownership of Cardinal gathering system.

Natural Gas Processing Facilities

	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Fort Beeler	Marshall County, WV	0.5	62	100%	Appalachian
Oak Grove	Marshall County, WV	0.2	25	100%	Appalachian

We also own and operate fractionation facilities at Moundsville, de-ethanization and condensate facilities at our Oak Grove plant, a condensate stabilization facility near our Moundsville fractionator, and an ethane transportation pipeline. Our condensate stabilizers are capable of handling approximately 17 Mbbls/d of field condensate. NGLs are extracted from the natural gas stream in our Oak Grove and Fort Beeler cryogenic processing plants. Our Oak Grove de-ethanizer is capable of handling up to approximately 80 Mbbls/d of mixed NGLs to extract up to approximately 40 Mbbls/d of ethane. Ethane produced at our de-ethanizer is transported to markets via our 50-mile ethane pipeline from Oak Grove to Houston, Pennsylvania. The remaining mixed NGL stream from the de-ethanizer is then transported via pipeline and fractionated at our Moundsville fractionation facilities, which are capable of handling approximately 43 Mbbls/d of mixed NGLs. The resulting products are then transported on truck or rail. Ohio Valley Midstream provides residue natural gas take away options for our customers with interconnections to three interstate transmission pipelines.

Northeast G&P Operating Statistics

	2018	2017	2016
Volumes: (1)			
Gathering (Bcf/d)	3.63	3.31	3.21
Plant inlet natural gas volumes (Bcf/d)	0.52	0.43	0.33
NGL production volumes (Mbbls/d) (2)	46	38	32

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(1) Excludes volumes associated with equity-method investments.

(2) Annual average Mbbls/d.

Certain Equity-Method Investments

Laurel Mountain

We own a 69 percent interest in a joint venture, Laurel Mountain, that includes a 2,053-mile gathering system that we operate in western Pennsylvania with the capacity to gather 0.6 Bcf/d of natural gas. Laurel Mountain has a long-term, dedicated, volumetric-based fee agreement, with exposure to natural gas prices, to gather the anchor customer's production in the western Pennsylvania area of the Marcellus Shale.

Caiman II

We own a 58 percent interest in Caiman II, which owns a 50 percent interest in Blue Racer, a joint project to own, operate, develop and acquire midstream assets in the Utica Shale and certain adjacent areas in the Marcellus Shale. Blue Racer's assets include 723 miles of gathering pipelines, and the Natrium complex in Marshall County, West Virginia, with a cryogenic processing capacity of 400 MMcf/d and fractionation capacity of approximately 134 Mbbls/d. Blue Racer also owns the Berne complex in Monroe County, Ohio, with a cryogenic processing capacity of 400 MMcf/d, and NGL and condensate pipelines connecting Natrium to Berne. Blue Racer provides gathering, processing, and marketing service primarily under percentage of liquids and fixed fee agreements.

Utica East Ohio Midstream

We own a 62 percent interest in UEOM, which includes infrastructure for the gathering, processing, and fractionation of natural gas and NGLs in the Utica Shale play in eastern Ohio. Our partner operates a natural gas gathering pipeline, inlet compression, two processing plants with a total capacity of 800 MMcf/d, 36 Mbbls/d of condensate stabilization capacity, a 135 Mbbls/d NGL fractionation facility, approximately 950,000 barrels of NGL storage capacity, and other ancillary assets, including loading and terminal facilities. These assets earn a fixed fee that escalates annually within a specified range.

Appalachia Midstream Investments

Through our Appalachia Midstream Investments, we operate 100 percent of and own an approximate average 66 percent interest in the Bradford Supply Hub gathering system and own an approximate average 68 percent interest in the Marcellus South gathering system, together which consist of approximately 1,028 miles of gathering pipeline in the Marcellus Shale region with the capacity to gather 4,623 MMcf/d of natural gas. The majority of our volumes in the region are gathered from northern Pennsylvania, southwestern Pennsylvania, and the northwestern panhandle of West Virginia in core areas of the Marcellus Shale. We operate the assets under long-term, 100 percent fixed-fee gathering agreements that include significant acreage dedications and, in the Bradford Supply Hub, a cost of service mechanism.

During the first quarter of 2017, we exchanged all of our 50 percent interest in the Delaware basin gas gathering system, previously reported within the West segment, for an increased interest in the Bradford Supply Hub natural gas gathering system that is part of the Appalachia Midstream Investments and $155 million in cash. 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 due to the significant participatory rights of our partners such that we do not exercise control. (See Note 6 – Investing Activities of Notes to Consolidated Financial Statements.)

Aux Sable

We also own a 15 percent interest in Aux Sable and its Channahon, Illinois, gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 132 Mbbls/d of extracted liquids into NGL products. Additionally, Aux Sable owns an 80 MMcf/d gas conditioning plant and a 12-inch, 83-mile gas pipeline infrastructure in North Dakota that provides additional NGLs to Channahon from the Bakken Shale in the Williston basin.

Atlantic-Gulf

This segment includes the Transco interstate natural gas pipeline that extends from the Gulf of Mexico to the eastern seaboard, as well as natural gas gathering, processing and treating, crude oil production handling, and NGL fractionation assets within the onshore, offshore shelf, and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama. This segment also includes various petrochemical and feedstock pipelines in the Gulf Coast region.

Transco

Transco is an interstate natural gas transmission company that owns and operates a 9,900-mile natural gas pipeline system, which is regulated by the FERC, extending from Texas, Louisiana, Mississippi, and the Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Delaware, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 12 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., Maryland, New York, New Jersey, and Pennsylvania.

At December 31, 2018, Transco's system, which extends from Texas to New York, had a system-wide delivery capacity totaling approximately 16.7 MMdth of natural gas per day. During 2018, Transco completed two fully-contracted expansions, which added more than 1.75 MMdth of firm transportation capacity per day to the existing pipeline system. Transco's system includes 55 compressor stations, four underground storage fields, and one LNG storage facility. Compression facilities at sea level-rated capacity total approximately 2.2 million horsepower. Transco has natural gas storage capacity in four underground storage fields located on or near its pipeline system or market areas and operates two of these storage fields. Transco also has storage capacity in an LNG storage facility that it owns and operates. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 200 Bcf of natural gas.

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At December 31, 2018, Transco’s customers had stored in its facilities approximately 130 Bcf of natural gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent equity-method investment in Pine Needle LNG Company, LLC, an LNG storage facility with 4 Bcf of storage capacity. Storage capacity permits Transco’s customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Gas Gathering, Processing, and Treating Assets

The following tables summarize the significant consolidated assets of this segment:

Natural Gas Gathering Assets

	Location	Pipeline Miles	Inlet Capacity (Bcf/d)	Ownership Interest	Supply Basins
Canyon Chief, including Blind Faith and Gulfstar extensions	Deepwater Gulf of Mexico	156	0.5	100%	Eastern Gulf of Mexico
Other Eastern Gulf	Offshore shelf and other	46	0.2	100%	Eastern Gulf of Mexico
Seahawk	Deepwater Gulf of Mexico	115	0.4	100%	Western Gulf of Mexico
Perdido Norte	Deepwater Gulf of Mexico	105	0.3	100%	Western Gulf of Mexico
Other Western Gulf	Offshore shelf and other	105	0.5	100%	Western Gulf of Mexico

Natural Gas Processing Facilities

	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Markham	Markham, TX	0.5	45	100%	Western Gulf of Mexico
Mobile Bay	Coden, AL	0.7	30	100%	Eastern Gulf of Mexico

Crude Oil Transportation and Production Handling Assets

In addition to our natural gas assets, we own and operate four deepwater crude oil pipelines and own production platforms serving the deepwater in the Gulf of Mexico. Our offshore floating production platforms provide centralized services to deepwater producers such as compression, separation, production handling, water removal, and pipeline landings.

The following tables summarize the significant crude oil transportation pipelines and production handling platforms of this segment:

Crude Oil Pipelines

	Pipeline Miles	Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Mountaineer, including Blind	155	150	100%	Eastern Gulf of Mexico

Faith and Gulfstar extensions				
BANJO	57	90	100%	Western Gulf of Mexico
Alpine	96	85	100%	Western Gulf of Mexico
Perdido Norte	74	150	100%	Western Gulf of Mexico

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Production Handling Platforms

	Gas Inlet Capacity (MMcf/d)	Crude/NGL Handling Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Devils Tower	210	60	100%	Eastern Gulf of Mexico
Gulfstar I FPS (1)	172	80	51%	Eastern Gulf of Mexico

(1) Statistics reflect 100 percent of the assets from our 51 percent interest in Gulfstar One.

Other NGL & Petchem Operations

We own 283 miles of pipeline systems in Louisiana and Texas that provide feedstock transportation from fractionation and storage facilities to various third-party crackers. These systems include the Bayou ethane pipeline, which provides ethane transportation from Mont Belvieu, Texas; certain ethane and propane systems in Louisiana; and a pipeline that has the capacity to transport 12 Mbbls/d of ethane from Discovery's Paradis fractionator.

We previously owned pipelines in the Houston Ship Channel area which were used to transport a variety of products including ethane, propane, ammonia, tertiary butyl alcohol, and other industrial products. These assets were sold in November 2018.

Atlantic-Gulf Operating Statistics

	2018	2017	2016
Volumes: (1)			
Interstate natural gas pipeline throughput (Tbtu)	4,309	3,783	3,503
Gathering (Bcf/d)	0.26	0.31	0.41
Plant inlet natural gas (Bcf/d)	0.50	0.55	0.72
NGL production (Mbbls/d) (2)	32	33	41
NGL equity sales (Mbbls/d) (2)	6	9	13
Crude oil transportation (Mbbls/d) (2)	140	134	113

(1) Excludes volumes associated with equity-method investments.
(2) Annual average Mbbls/d.

Certain Equity-Method Investments

Discovery

We own a 60 percent interest in and operate the facilities of Discovery. Discovery's assets include a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32 Mbbls/d NGL fractionator plant near Paradis, Louisiana, and a 594-mile offshore natural gas gathering and transportation system in the Gulf of Mexico. Discovery's mainline has a gathering inlet capacity of 600 MMcf/d, while the Keathley Canyon Connector, a deepwater lateral pipeline in the central deepwater Gulf of Mexico has a gathering inlet capacity of 400 MMcf/d. Discovery's assets also include a crude oil production handling platform with a crude oil/NGL handling capacity of 10 Mbbls/d and natural gas processing capacity of 75 MMcf/d.

Gulfstream

Gulfstream is a 745-mile interstate natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida, which has a capacity to transport 1.3 Bcf/d. We own, through a subsidiary, a 50 percent equity-method investment in Gulfstream. We share operating responsibilities for Gulfstream with the other 50 percent owner.

West

This segment includes the Northwest Pipeline interstate natural gas pipeline, as well as natural gas gathering, processing, and treating assets in Colorado, Wyoming, Louisiana, Texas, Arkansas, and Oklahoma. This segment also includes an NGL and natural gas marketing business, storage facilities, and an undivided 50 percent interest in an NGL fractionator near Conway, Kansas.

Northwest Pipeline

Northwest Pipeline is an interstate natural gas transmission company that owns and operates a natural gas pipeline system, which is regulated by the FERC, extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon, and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in Washington, Oregon, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico, California, and Arizona, either directly or indirectly through interconnections with other pipelines.

At December 31, 2018, Northwest Pipeline’s system, having long-term firm transportation and storage redelivery agreements with aggregate capacity reservations of approximately 3.9 MMdth/d, was composed of approximately 3,900 miles of mainline and lateral transmission pipeline and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 472,000 horsepower.

Northwest Pipeline owns a one-third interest in the Jackson Prairie underground storage facility in Washington and contracts with a third party for natural gas storage services in the Clay basin underground field in Utah. Northwest Pipeline also owns and operates an LNG storage facility in Washington. These storage facilities have an aggregate working natural gas storage capacity of 14.2 MMdth of natural gas, which is substantially utilized for third-party natural gas. These natural gas storage facilities enable Northwest Pipeline to balance daily receipts and deliveries and provide storage services to customers.

Gas Gathering, Processing, and Treating Assets

The following tables summarize the significant consolidated assets of this segment:

Natural Gas Gathering Assets

	Location	Pipeline Miles	Inlet Capacity (Bcf/d)	Ownership Interest	Supply Basins/Shale Formations
Wamsutter	Wyoming	2,084	0.7	100%	Wamsutter
Southwest Wyoming	Wyoming	1,614	0.5	100%	Southwest Wyoming
Piceance	Colorado	352	1.8	(1)	Piceance
Barnett Shale	Texas	845	0.8	100%	Barnett Shale
Eagle Ford Shale	Texas	1,275	0.6	100%	Eagle Ford Shale
Haynesville Shale	Louisiana	626	1.8	100%	Haynesville Shale
Permian	Texas	100	0.1	100%	Permian
Mid-Continent	Oklahoma & Texas	2,248	0.9	100%	Miss-Lime, Granite Wash, Colony Wash, Arkoma

(1) Includes our 60 percent ownership of a gathering system in the Ryan Gulch area with 140 miles of pipeline and 0.2 Bcf/d of inlet capacity, and our 67 percent ownership of a gathering system at Allen Point with 8 miles of pipeline and 0.1 Bcf/d of inlet capacity. We operate both systems. We own and operate 100 percent of the balance of the Piceance gathering assets.

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Natural Gas Processing Facilities

	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Echo Springs	Echo Springs, WY	0.7	58	100%	Wamsutter
Opal	Opal, WY	1.1	47	100%	Southwest Wyoming
Willow Creek	Rio Blanco County, CO	0.5	30	100%	Piceance
Parachute	Garfield County, CO	1.1	6	100%	Piceance

Marketing Services

We market NGL products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets our equity NGLs from the production at our processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of our fee-based processing customers, and the NGL volumes owned by Discovery. The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points. In order to meet sales contract obligations, we may purchase products in the spot market for resale.

In certain situations to facilitate our gas gathering and processing activities, we buy natural gas from our producer customers for resale.

Other NGL Operations

We own interests in and/or operate NGL fractionation and storage assets in central Kansas near Conway. These assets include a 50 percent interest in an NGL fractionation facility with capacity of slightly more than 100 Mbbls/d and we own approximately 20 million barrels of NGL storage capacity.

West Operating Statistics

	2018	2017	2016
Volumes:			
Interstate natural gas pipeline throughput (Tbtu)	820	750	727
Gathering (Bcf/d)	4.27	4.53	4.62
Plant inlet natural gas (Bcf/d)	2.01	2.07	2.45
NGL production (Mbbls/d) (1)	84	77	78
NGL equity sales (Mbbls/d) (1)	33	29	28

(1) Annual average Mbbls/d.

Certain Equity-Method Investments

Jackalope gathering system

We operate and own a 50 percent interest in Jackalope which provides gas gathering and processing services for the Powder River basin. During the second quarter of 2018, we deconsolidated Jackalope (see Note 4 – Variable Interest Entities of Notes to Consolidated Financial Statements). Jackalope, which includes the Bucking Horse gas processing plant, consists of a 257-mile natural gas pipeline, 0.2 Bcf/d of gas gathering inlet capacity, 0.1 Bcf/d of natural gas processing inlet capacity, and 12 Mbbls/d of NGL production capacity.

Brazos Permian II

We acquired a non-operated 15 percent interest in Brazos Permian II in December 2018 by contributing cash and our existing Delaware basin assets. This partnership consists of 725 miles of gas gathering pipelines, 260 MMcf/d of natural gas processing inlet capacity, and 75 miles of crude oil gathering pipelines.

Rocky Mountain Midstream

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. As of December 31, 2018, we own 50 percent of RMM. RMM consists of 60 MMcf/d of gas processing capacity, an approximate 105-mile natural gas gathering system, and an approximate 70-mile oil gathering system. There are two additional processing plants currently under construction that are expected to increase natural gas processing capacity to 480 MMcf/d by the end of 2019.

Delaware basin gas gathering system

We previously owned a non-operated 50 percent interest in the Delaware basin gas gathering system in the Permian basin, which was sold in February 2017. The system was comprised of more than 450 miles of gathering pipeline, located in west Texas.

Overland Pass Pipeline

We also operate and own a 50 percent interest in OPPL. OPPL is capable of transporting 255 Mbbls/d and includes approximately 1,035 miles of NGL pipeline extending from Opal, Wyoming, to the Mid-Continent NGL market center near Conway, Kansas, along with extensions into the Piceance and Denver-Julesberg basins in Colorado and the Bakken Shale in the Williston basin in North Dakota. Our equity NGL volumes from two of our three Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term transportation agreement. NGL volumes from our RMM equity-method investment are also expected to be transported on OPPL.

Other

Other includes our previously owned operations, minor business activities that are not operating segments, as well as corporate operations.

Geismar Interest

In July 2017, we completed the sale of 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). Upon closing 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.

Canadian Operations

We completed the sale of our Canadian operations in September 2016. This business included an oil sands offgas processing plant located near Fort McMurray, Alberta, and an NGL/olefin fractionation facility located at Redwater, Alberta, which is near Edmonton, Alberta, and the Boreal Pipeline which transported NGLs and associated olefins from the Fort McMurray plant to the Redwater fractionation facility. This business allowed us to extract, fractionate, treat, store, terminal, and sell the ethane/ethylene, propane, propylene, normal butane, iso-butane, alky feedstock, and condensate recovered from a third-party oil sands bitumen upgrader.

Service Assets, Customers, and Contracts

Interstate Natural Gas Pipeline Assets

Our interstate natural gas pipelines are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce are subject to regulation. The rates are established through the FERC's ratemaking process.

Our interstate natural gas pipelines transport and store natural gas for a broad mix of customers, including local natural gas distribution companies, public utilities, municipalities, direct industrial users, electric power generators, and natural gas marketers and producers. We have firm transportation and storage contracts that are generally long-term contracts with various expiration dates and account for the major portion of our regulated businesses. Additionally, we offer storage services and interruptible transportation services under shorter-term agreements.
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.

Gathering, Processing and Treating Assets
Our gathering systems receive natural gas from producers' oil and natural gas wells and gather these volumes to gas processing, treating or redelivery facilities. Typically, natural gas, in its raw form, is not acceptable for transportation in major interstate natural gas pipelines or for commercial use as a fuel. Our treating facilities remove water vapor, carbon dioxide and other contaminants and collect condensate, but do not extract NGLs. We are generally paid a fee based on the volume of natural gas gathered and/or treated, generally measured in the Btu heating value.

In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Our processing plants extract the NGLs in addition to removing water vapor, carbon dioxide, and other contaminants. NGL products include:

- Ethane, primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for plastics;
- Propane, used for heating, fuel and as a petrochemical feedstock in the production of ethylene and propylene, another building block for petrochemical-based products such as carpets, packing materials, and molded plastic parts;
- Normal butane, isobutane, and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Our gas processing services generate revenues primarily from the following types of contracts:

- Fee-based: We are paid a fee based on the volume of natural gas processed, generally measured in the Btu heating value. Our customers are entitled to the NGLs produced in connection with this type of processing agreement. A portion of our fee-based processing revenue includes a share of the margins on the NGLs produced. For the year ended December 31, 2018, 74 percent of our NGL production volumes were under fee-based contracts.
- Noncash commodity-based: We also process gas under two types of commodity-based contracts, keep-whole and percent-of-liquids, where we receive consideration for our services in the form of NGLs. Under these contracts, we retain some or all of the extracted NGLs as compensation for our services. For a keep-whole arrangement we replace the Btu content of the retained NGLs that were extracted during processing with natural gas purchases, also known as shrink replacement gas. For a percent-of-liquids arrangement, we deliver to customers an agreed-upon percentage of the extracted NGLs and retain the remainder. NGLs we retain in connection with these types of processing agreements are referred to as our equity NGL production. Under keep-whole agreements, we have commodity price exposure on the difference between NGL and natural gas prices. For the year ended December 31, 2018, 26 percent of our NGL production volumes were under noncash commodity-based contracts.

Our gathering and processing agreements have terms ranging from month-to-month to the life of the producing lease. Generally, our gathering and processing agreements are long-term agreements. Some contracts have price escalators which annually increase our gathering rates. In addition, certain contracts include fee redetermination or cost of service mechanisms that are designed to support a return on invested capital and allow our gathering rates to be adjusted, subject to specified caps in certain cases, to account for variability in volume, capital expenditures, commodity price fluctuations, compression and other expenses. Certain of our gas gathering agreements include MVCs. If a customer under such an agreement fails to meet its MVC for a specified period, 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 is probable that the customer will not exercise all or a portion of its remaining rights, we recognize revenue in an amount in proportion to the pattern of exercised rights within the respective MVC period.

Demand for gas gathering and processing services is dependent on producers' drilling activities, which is impacted by the strength of the economy, natural gas prices, and the resulting demand for natural gas by manufacturing and industrial companies and consumers. Our gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2018, our facilities gathered and processed gas and crude oil for approximately 260 customers. Our top ten customers accounted for approximately 70 percent of our gathering and processing fee revenues and NGL margins from our noncash commodity-based agreements.

Demand for our equity NGLs is affected by economic conditions and the resulting demand from industries using these commodities to produce petrochemical-based products such as plastics, carpets, packing materials, and blending stocks for motor gasoline and the demand from consumers using these commodities for heating and fuel. NGL products are currently the preferred feedstock for ethylene and propylene production, which has shifted away from the more expensive crude-based feedstocks.

Key variables for our business will continue to be:

- Producer drilling activities impacting natural gas supplies supporting our gathering and processing volumes;
- Prices impacting our commodity-based activities;
- Retaining and attracting customers by continuing to provide reliable services;
- Revenue growth associated with additional infrastructure either completed or currently under construction;
- Disciplined growth in our service areas.

Crude Oil Transportation and Production Handling Assets

Our crude oil transportation revenues are typically volumetric-based fee arrangements. Crude oil marketing activity is now presented on a net basis within Product costs in the Consolidated Statement of Operations in 2018 in conjunction with the adoption of ASC 606. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements.) Revenue sources have historically included a combination of fixed-fee, volumetric-based fee, and cost reimbursement arrangements. Fixed fees associated with the resident production at our Devils Tower facility are recognized on a units-of-production basis. Fixed fees associated with the resident production at our Gulfstar One facility are recognized as the guaranteed capacity is made available.

Additional Business Segment Information

We perform certain management, legal, financial, tax, consultation, information technology, administrative, and other services for our subsidiaries.

Our principal sources of cash are from dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, and, if needed, external financings, and net proceeds from asset sales. The terms of

our credit agreement, which also govern certain subsidiaries' borrowing arrangements, may limit the transfer of funds to us under certain conditions.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. Our interstate pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

FERC

Our gas pipeline interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, our rates and charges for the transportation of natural gas in interstate commerce, accounting, and the extension, enlargement, or abandonment of our jurisdictional facilities, among other things, are subject to regulation. Each of our gas pipeline companies holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities, and properties for which certificates are required under the NGA. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with gas marketing employees. Among other things, the Standards of Conduct require that interstate gas pipelines not operate their systems to preferentially benefit gas marketing functions.

FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect. Our interstate gas pipeline companies establish rates through the FERC's ratemaking process. In addition, our interstate gas pipelines may enter into negotiated rate agreements where cost-based recourse rates are made available. Key determinants in the FERC ratemaking process include:

- Costs of providing service, including depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Contract and volume throughput assumptions.

The allowed rate of return is determined in each rate case. Rate design and the allocation of costs between the reservation and commodity rates also impact profitability. As a result of these proceedings, certain revenues previously collected may be subject to refund.

We also own interests in and operate two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank, and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. In addition, we own a 50 percent equity-method investment in and are the operator of OPPL, which is an interstate natural gas liquids pipeline regulated by the FERC pursuant to the Interstate Commerce Act. OPPL provides transportation service pursuant to tariffs filed with the FERC. We also own an ethane pipeline in West Virginia and Pennsylvania (Williams Ohio Valley Pipeline LLC) and an ethane pipeline in Texas and Louisiana (Williams Bayou Ethane Pipeline) each of which provides interstate service subject to FERC jurisdiction under the Interstate Commerce Act.

Pipeline Safety

Our gas pipelines are subject to the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Improvement Act of 2002, the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011 (Pipeline Safety Act), and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which regulate safety requirements in the design, construction, operation, and maintenance of interstate natural gas transmission facilities.

The United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) administers federal pipeline safety laws.

Federal pipeline safety laws authorize PHMSA to establish minimum safety standards for pipeline facilities and persons engaged in the transportation of gas or hazardous liquids by pipeline. These safety standards apply to the design, construction, testing, operation, and maintenance of gas and hazardous liquids pipeline facilities affecting interstate or foreign commerce. PHMSA has also established reporting requirements for operators of gas and hazardous liquid pipeline facilities, as well as provisions for establishing the qualification of pipeline personnel and requirements for managing the integrity of gas transmission and distribution lines and certain hazardous liquid pipelines. To ensure compliance with these provisions, PHMSA performs pipeline safety inspections and has the authority to initiate enforcement actions.

Federal pipeline safety regulations contain an exemption that applies to gathering lines in certain rural locations. A substantial portion of our gathering lines qualify for that exemption and are currently not regulated under federal law. States are largely preempted by federal law from regulating pipeline safety for interstate pipelines but most are certified by PHMSA to assume responsibility for enforcing intrastate pipeline safety regulations and inspecting intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, they vary considerably in their authority and capacity to address pipeline safety.

Pipeline Integrity Regulations

We have an enterprise-wide Gas Integrity Management Plan that we believe meets the PHMSA final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires gas pipeline operators to develop an integrity management program for gas transmission pipelines that could affect high-consequence areas in the event of pipeline failure. The integrity management program includes a baseline assessment plan along with periodic reassessments to be completed within required time frames. In meeting the integrity regulations, we have identified high-consequence areas and developed baseline assessment plans. Ongoing periodic reassessments and initial assessments of any new high-consequence areas have been completed. We estimate that the cost to be incurred in 2019 associated with this program to be approximately $86 million. Management considers costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through Northwest Pipeline’s and Transco’s rates.

We have an enterprise-wide Liquid Integrity Management Plan that we believe meets the PHMSA final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires liquid pipeline operators to develop an integrity management program for liquid transmission pipelines that could affect high-consequence areas in the event of pipeline failure. The integrity management program includes a baseline assessment plan along with periodic reassessments expected to be completed within required time frames. In meeting the integrity regulations, we utilized government defined high-consequence areas and developed baseline assessment plans. We completed assessments within the required time frames. We estimate that the cost to be incurred in 2019 associated with this program will be approximately $3 million. Ongoing periodic reassessments and initial assessments of any new high-consequence areas are expected to be completed within the time frames required by the rule. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business.

State Gathering Regulations

Our onshore midstream gathering operations are subject to laws and regulations in the various states in which we operate. For example, the Texas Railroad Commission has the authority to regulate the terms of service for our intrastate natural gas gathering business in Texas. Although the applicable state regulations vary widely, they generally require that pipeline rates and practices be reasonable and nondiscriminatory, and may include provisions covering marketing, pricing, pollution, environment, and human health and safety. Some states, such as New York, have specific regulations pertaining to the design, construction, and operations of gathering lines within such state.

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Intrastate Liquids Pipelines in the Gulf Coast

Our intrastate liquids pipelines in the Gulf Coast are regulated by the Louisiana Public Service Commission, the Texas Railroad Commission, and various other state and federal agencies. These pipelines are also subject to the liquid pipeline safety and integrity regulations discussed above since both Louisiana and Texas have adopted the integrity management regulations defined in PHMSA.

OCSLA

Our offshore gas and liquids pipelines located on the outer continental shelf are subject to the Outer Continental Shelf Lands Act, which provides in part that outer continental shelf pipelines “must provide open and nondiscriminatory access to both owner and nonowner shippers.”

See Part II, Item 8. Financial Statements and Supplementary Data — Note 18 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements for further details on our regulatory matters. For additional information regarding regulatory matters, please also refer to Part 1, Item 1A. “Risk Factors” — “The operation of our businesses might be adversely affected by regulatory proceedings, changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers,” and “The natural gas sales, transportation, and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return.”

ENVIRONMENTAL MATTERS

Our operations are subject to federal environmental laws and regulations as well as the state, local, and tribal laws and regulations adopted by the jurisdictions in which we operate. We could incur liability to governments or third parties for any unlawful discharge of pollutants into the air, soil, or water, as well as liability for cleanup costs. Materials could be released into the environment in several ways including, but not limited to:

- Leakage from gathering systems, underground gas storage caverns, pipelines, processing or treating facilities, transportation facilities, and storage tanks;
- Damage to facilities resulting from accidents during normal operations;
- Damages to onshore and offshore equipment and facilities resulting from storm events or natural disasters;
- Blowouts, cratering, and explosions.

In addition, we may be liable for environmental damage caused by former owners or operators of our properties.

We believe compliance with current environmental laws and regulations will not have a material adverse effect on our capital expenditures, earnings, or current competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, fines and penalties, and creating the need to seek relief from the FERC for rate increases to recover the costs of certain capital expenditures and operation and maintenance expenses.

For additional information regarding the potential impact of federal, state, tribal, or local regulatory measures on our business and specific environmental issues, please refer to Part 1, Item 1A. “Risk Factors” — “Our operations are subject to environmental laws and regulations, including laws and regulations relating to climate change and greenhouse gas emissions, which may expose us to significant costs, liabilities, and expenditures that could exceed our expectations,” and Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Environmental” and “Environmental Matters” in Part II, Item 8. Financial Statements and Supplementary Data — Note 18 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements.

COMPETITION

Gas Pipeline Business

The market for supplying natural gas is highly competitive and new pipelines, storage facilities, and other related services are expanding to service the growing demand for natural gas. Additionally, pipeline capacity in many growing natural gas supply basins is constrained causing competition to increase among pipeline companies as they strive to connect those basins to major natural gas demand centers.

In our business, we compete with major intrastate and interstate natural gas pipelines. In the last few years, local distribution companies have also started entering into the long-haul transportation business through joint venture pipelines. The principle elements of competition in the interstate natural gas pipeline business are based on rates, reliability, quality of customer service, diversity of supply, and proximity to customers and market hubs.

Significant entrance barriers to build new pipelines exist, including federal and growing state regulations and public opposition against new pipeline builds, and these factors will continue to impact potential competition for the foreseeable future. However, we believe the position of our existing infrastructure, established strategic long-term contracts, and the fact that our pipelines have numerous receipt and delivery points along our systems provide us a competitive advantage, especially along the eastern seaboard and northwestern United States.

Midstream Business

Competition for natural gas gathering, processing, treating, transporting, and storing natural gas continues to increase as production from shales and other resource areas continues to grow. Our midstream services compete with similar facilities that are in the same proximity as our assets.

We face competition from major and independent natural gas midstream providers, private equity firms, and major integrated oil and natural gas companies that gather, transport, process, fractionate, store, and market natural gas and NGLs, as well as some larger exploration and production companies that are choosing to develop midstream services to handle their own natural gas.

Our gathering and processing agreements are generally long-term agreements that may include acreage dedication. We primarily face competition to the extent these agreements approach renewal and new volume opportunities arise. Competition for natural gas volumes is primarily based on reputation, commercial terms (products retained or fees charged), array of services provided, efficiency and reliability of services, location of gathering facilities, available capacity, downstream interconnects, and latent capacity. We believe our significant presence in traditional prolific supply basins, our solid positions in growing shale plays, our reputation as a reliable operator, and our ability to offer integrated packages of services position us well against our competition.

For additional information regarding competition for our services or otherwise affecting our business, please refer to Part 1, Item 1A. “Risk Factors” - “The financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access and demand for those supplies in the markets we serve,” “Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results,” and “We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.”

EMPLOYEES

At February 1, 2019, we had 5,322 full-time employees.

Item 1A. Risk Factors

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT
FOR PURPOSES OF THE “SAFE HARBOR” PROVISIONS OF
THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

The reports, filings, and other public announcements of 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. 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 as discussed below. 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 our capital projects and 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 and regulations (including but not limited to the Tax Cuts and Jobs Act of 2017), 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, as well as our ability to obtain sufficient construction related inputs including skilled labor;
- 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.

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. These factors are described in the following section.

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information in this report. Each of these factors could adversely affect our business, prospects, financial condition, results of operations, cash flows, and, in some cases our reputation. The occurrence of any of such risks could also adversely affect the value of an investment in our securities.

Risks Related to Our Business

The financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access and demand for those supplies in the markets we serve.

Our ability to maintain and expand our natural gas transportation and midstream businesses depends on the level of drilling and production by third parties in our supply basins. Production from existing wells and natural gas supply basins with access to our pipeline and gathering systems will naturally decline over time. The amount of natural gas reserves underlying these existing wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. We do not obtain independent evaluations of natural gas reserves connected to our systems and processing facilities. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. In addition, low prices for natural gas, regulatory limitations, or the lack of available capital could adversely affect the development and production of additional natural gas reserves, the installation of gathering, storage, and pipeline transportation facilities and the import and export of natural gas supplies. Localized low natural gas prices in one or more of our existing supply basins, whether caused by a lack of infrastructure or otherwise, could also result in depressed natural gas production in such basins and limit the supply of natural gas made available to us. The competition for natural gas supplies to serve other markets could also reduce the amount of natural gas supply for our customers. A failure to obtain access to sufficient natural gas supplies will adversely impact our ability to maximize the capacities of our gathering, transportation, and processing facilities.

Demand for our services is dependent on the demand for gas in the markets we serve. Alternative fuel sources such as electricity, coal, fuel oils, or nuclear energy, as well as technological advances and renewable sources of energy, could reduce demand for natural gas in our markets and have an adverse effect on our business.

A failure to obtain access to sufficient natural gas supplies or a reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Prices for natural gas, NGLs, oil, and other commodities, are volatile and this volatility has and could continue to adversely affect our financial results, cash flows, access to capital, and ability to maintain our existing businesses.
Our revenues, operating results, future rate of growth, and the value of certain components of our businesses depend primarily upon the prices of natural gas, NGLs, oil, or other commodities, and the differences between prices of these

commodities and could be materially adversely affected by an extended period of low commodity prices, or a decline in commodity prices. Price volatility has and could continue to impact both the amount we receive for our products and services and the volume of products and services we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Price volatility has and could continue to have an adverse effect on our business, results of operations, financial condition, and cash flows.

The markets for natural gas, NGLs, oil, and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from one or more factors beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, NGLs, oil, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- The level of consumer demand;
- The price and availability of other types of fuels or feedstocks;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and quantity of foreign imports and domestic exports of natural gas and oil;
- Domestic and foreign governmental regulations and taxes;
- The credit of participants in the markets where products are bought and sold.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management will not be able to completely eliminate such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, our customers are rated investment grade, are otherwise considered creditworthy, or are required to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies cannot completely eliminate customer and counterparty credit risk. Our customers and counterparties include industrial customers, local distribution companies, natural gas producers, and marketers whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities. In a low commodity price environment certain of our customers could be negatively impacted, causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with the customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness, and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

We face opposition to operation and expansion of our pipelines and facilities from various individuals and groups.

We have experienced, and we anticipate that we will continue to face, opposition to the operation and expansion of our pipelines and facilities from governmental officials, environmental groups, landowners, tribal groups, local groups and other advocates. In some instances, we encounter opposition which disfavors hydrocarbon-based energy supplies regardless of practical implementation or financial considerations. Opposition to our operation and expansion can take many forms, including the delay or denial of required governmental permits, organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation or expansion of our assets and business. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that delays or prevents the expansion of our business, that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could adversely affect our financial condition and results of operations.

We may not be able to grow or effectively manage our growth.

As part of our growth strategy, we consider acquisition opportunities and engage in significant capital projects. We have both a project lifecycle process and an investment evaluation process. These are processes we use to identify, evaluate, and execute on acquisition opportunities and capital projects. We may not always have sufficient and accurate information to identify and value potential opportunities and risks or our investment evaluation process may be incomplete or flawed. Regarding potential acquisitions, suitable acquisition candidates or assets may not be available on terms and conditions we find acceptable or, where multiple parties are trying to acquire an acquisition candidate or assets, we may not be chosen as the acquirer. If we are able to acquire a targeted business, we may not be able to successfully integrate the acquired businesses and realize anticipated benefits in a timely manner.

Our growth may also be dependent upon the construction of new natural gas gathering, transportation, compression, processing or treating pipelines, and facilities, NGL transportation, or fractionation or storage facilities as well as the expansion of existing facilities. Additional risks associated with construction may include the inability to obtain rights-of-way, skilled labor, equipment, materials, and other required inputs in a timely manner such that projects are completed, on time or at all, and the risk that construction cost overruns could cause total project costs to exceed budgeted costs. Additional risks associated with growing our business include, among others, that:

- Changing circumstances and deviations in variables could negatively impact our investment analysis, including our projections of revenues, earnings, and cash flow relating to potential investment targets, resulting in outcomes which are materially different than anticipated;

- We could be required to contribute additional capital to support acquired businesses or assets;

- We may assume liabilities that were not disclosed to us, that exceed our estimates and for which contractual protections are either unavailable or prove inadequate;

- Acquisitions could disrupt our ongoing business, distract management, divert financial and operational resources from existing operations and make it difficult to maintain our current business standards, controls, and procedures;

- Acquisitions and capital projects may require substantial new capital, including proceeds from the issuance of debt or equity, and we may not be able to access capital markets or obtain acceptable terms.

If realized, any of these risks could have an adverse impact on our financial condition, results of operations, including the possible impairment of our assets, or cash flows.

Holders of our common stock may not receive dividends in the amount expected or any dividends.
We may not have sufficient cash each quarter to pay dividends or maintain current or expected levels of dividends. The actual amount of cash we dividend may fluctuate from quarter to quarter and will depend on various factors, some of which are beyond our control, including:

- The amount of cash that our subsidiaries distribute to us;

- The amount of cash we generate from our operations, our working capital needs, our level of capital expenditures, and our ability to borrow;

- The restrictions contained in our indentures and credit facility and our debt service requirements;

- The cost of acquisitions, if any.

A failure either to pay dividends or to pay dividends at expected levels could result in a loss of investor confidence, reputational damage, and a decrease in the value of our stock price.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.
We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Any current or future competitor that delivers natural gas, NGLs, or other commodities into the areas that we operate could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make strategic investments or acquisitions. Our competitors may be able to respond more quickly to new laws or regulations or emerging technologies or to devote greater resources to the construction, expansion, or refurbishment of their facilities than we can. Failure to successfully compete against current and future competitors could have a material adverse effect on our business, results of operations, financial condition, and cash flows.

We do not own 100 percent of the equity interests of certain subsidiaries, including the Partially Owned Entities, which may limit our ability to operate and control these subsidiaries. Certain operations, including the Partially Owned Entities, are conducted through arrangements that may limit our ability to operate and control these operations.

The operations of our current non-wholly-owned subsidiaries, including the Partially Owned Entities, are conducted in accordance with their organizational documents. We anticipate that we will enter into more such arrangements, including through new joint venture structures or new Partially Owned Entities. We may have limited operational flexibility in such current and future arrangements and we may not be able to control the timing or amount of cash distributions received. In certain cases:

- We cannot control the amount of cash reserves determined to be necessary to operate the business, which reduces cash available for distributions;

- We cannot control the amount of capital expenditures that we are required to fund and we are dependent on third parties to fund their required share of capital expenditures;

- We may be subject to restrictions or limitations on our ability to sell or transfer our interests in the jointly owned assets;

- We may be forced to offer rights of participation to other joint venture participants in the area of mutual interest;

- We have limited ability to influence or control certain day to day activities affecting the operations;
- We may have additional obligations, such as required capital contributions, that are important to the success of the operations.

In addition, conflicts of interest may arise between us, on the one hand, and other interest owners, on the other hand. If such conflicts of interest arise, we may not have the ability to control the outcome with respect to the matter in question. Disputes between us and other interest owners may also result in delays, litigation or operational impasses.

The risks described above or the failure to continue such arrangements could adversely affect our ability to conduct the operations that are the subject of such arrangements which could, in turn, negatively affect our business, growth strategy, financial condition and results of operations.

We may not be able to replace, extend, or add additional customer contracts or contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay dividends, and our ability to grow.
We rely on a limited number of customers and producers for a significant portion of our revenues and supply of natural gas and NGLs. Although many of our customers and suppliers are subject to long-term contracts, if we are unable to replace or extend such contracts, add additional customers, or otherwise increase the contracted volumes of natural gas provided to us by current producers, in each case on favorable terms, if at all, our financial condition, growth plans, and the amount of cash available to pay dividends could be adversely affected. Our ability to replace, extend, or add additional customer or supplier contracts, or increase contracted volumes of natural gas from current producers, on favorable terms, or at all, is subject to a number of factors, some of which are beyond our control, including:

- The level of existing and new competition in our businesses or from alternative sources, such as electricity, renewable resources, coal, fuel oils, or nuclear energy;
- Natural gas and NGL prices, demand, availability, and margins in our markets. Higher prices for energy commodities related to our businesses could result in a decline in the demand for those commodities and, therefore, in customer contracts or throughput on our pipeline systems. Also, lower energy commodity prices could negatively impact our ability to maintain or achieve favorable contractual terms, including pricing, and could also result in a decline in the production of energy commodities resulting in reduced customer contracts, supply contracts, and throughput on our pipeline systems;
- General economic, financial markets, and industry conditions;
- The effects of regulation on us, our customers, and our contracting practices;
- Our ability to understand our customers' expectations, efficiently and reliably deliver high quality services and effectively manage customer relationships. The results of these efforts will impact our reputation and positioning in the market.

Certain of our gas pipeline services are subject to long-term, fixed-price contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts.

Our gas pipelines provide some services pursuant to long-term, fixed-price contracts. It is possible that costs to perform services under such contracts will exceed the revenues our pipelines collect for their services. Although most of the services are priced at cost-based rates that are subject to adjustment in rate cases, under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a “negotiated rate” that may be above or below the FERC regulated cost-based rate for that service. These “negotiated rate” contracts are not generally subject to adjustment for increased costs that could be produced by inflation or other factors relating to the specific facilities being used to perform the services.

Some of our businesses are exposed to supplier concentration risks arising from dependence on a single or a limited number of suppliers.

Some of our businesses may be dependent on a small number of suppliers for delivery of critical goods or services. If a supplier on which one of our businesses depends were to fail to timely supply required goods and services, such business may not be able to replace such goods and services in a timely manner or otherwise on favorable terms or at all. If our business is unable to adequately diversify or otherwise mitigate such supplier concentration risks and such risks were realized, such businesses could be subject to reduced revenues and increased expenses, which could have a material adverse effect on our financial condition, results of operation, and cash flows.

Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Certain of our accounting and information technology services are currently provided by third-party vendors, and sometimes from service centers outside of the United States. Services provided pursuant to these agreements could be disrupted. Similarly, the expiration of such agreements or the transition of services between providers could lead to loss of institutional knowledge or service disruptions. Our reliance on others as service providers could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

An impairment of our assets, including property, plant, and equipment, intangible assets, and/or equity-method investments, could reduce our earnings.

GAAP requires us to test certain assets for impairment on either an annual basis or when events or circumstances occur which indicate that the carrying value of such assets might be impaired. The outcome of such testing could result in impairments of our assets including our property, plant, and equipment, intangible assets, and/or equity-method investments. Additionally, any asset monetizations could result in impairments if any assets are sold or otherwise exchanged for amounts less than their carrying value. If we determine that an impairment has occurred, we would be required to take an immediate noncash charge to earnings.

Our operations are subject to operational hazards and unforeseen interruptions.

There are operational risks associated with the gathering, transporting, storage, processing, and treating of natural gas, the fractionation, transportation, and storage of NGLs, and crude oil transportation and production handling, including:

- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), NGLs, crude oil, or other products;
- Collapse or failure of storage caverns;
- Operator error;
- Damage caused by third-party activity, such as operation of construction equipment;
- Pollution and other environmental risks;
- Fires, explosions, craterings, and blowouts;

- Security risks, including cybersecurity;

• Operating in a marine environment.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations, loss of services to our customers, reputational damage, and substantial losses to us. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. An event such as those described above could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance.

We do not insure against all potential risks and losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.
In accordance with customary industry practice, we maintain insurance against some, but not all, risks and losses, and only at levels we believe to be appropriate. The occurrence of any risks not fully covered by our insurance could have a material adverse effect on our business, financial condition, results of operations, and cash flows and our ability to repay our debt.

Our assets and operations, as well as our customers' assets and operations, can be adversely affected by weather and other natural phenomena.

Our assets and operations, especially those located offshore, and our customers' assets and operations can be adversely affected by hurricanes, floods, earthquakes, landslides, tornadoes, fires, and other natural phenomena and weather conditions, including extreme or unseasonable temperatures, making it more difficult for us to realize the historic rates of return associated with our assets and operations. A significant disruption in our or our customers' operations or a significant liability for which we are not fully insured could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our business could be negatively impacted by acts of terrorism and related disruptions.

Given the volatile nature of the commodities we transport, process, store, and sell, our assets and the assets of our customers and others in our industry may be targets of terrorist activities. A terrorist attack could create significant price volatility, disrupt our business, limit our access to capital markets, or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, or distribute natural gas, NGLs, or other commodities. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

A breach of our information technology infrastructure, including a breach caused by a cybersecurity attack on us or third parties with whom we are interconnected, may interfere with the safe operation of our assets, result in the disclosure of personal or proprietary information, and harm our reputation.

We rely on our information technology infrastructure to process, transmit, and store electronic information, including information we use to safely operate our assets. Our Board of Directors has oversight responsibility with regard to assessment of the major risks inherent in our business, including cybersecurity risks, and reviews management's efforts to address and mitigate such risks, including the establishment and implementation of policies to address cybersecurity threats. We have invested, and expect to continue to invest, significant time, manpower and capital in our information technology infrastructure. However, the age, operating systems, or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats. While we believe that we maintain appropriate information security policies, practices, and protocols, we regularly face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational industrial control systems that are used to operate our pipelines, plants, and assets. We face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, “hacktivists”, or private individuals. We face the threat of theft and misuse of sensitive data and information, including customer and employee information. We also face attempts to gain access to information related to our assets through attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information. We also are subject to cybersecurity risks arising from the fact that our business operations are interconnected with third parties, including third-party pipelines, other facilities and our contractors and vendors. In addition, the breach of certain business systems could affect our ability to correctly record, process and report financial information. Breaches in our information technology infrastructure or physical facilities, or other disruptions including those arising from theft, vandalism, fraud, or unethical conduct, could result in damage to or destruction of our assets, unnecessary waste, safety incidents, damage to the environment, reputational damage, potential liability, the loss of contracts, the imposition of significant costs associated with remediation and litigation, heightened regulatory scrutiny, increased insurance costs, and a material adverse effect on our operations, financial condition, results of operations, and cash flows.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas and NGLs or to treat natural gas, our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Because we do not own these third-party pipelines or other facilities, their continuing operation is not within our control. If these pipelines or facilities were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines or facilities, reduced operating pressures, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or other causes, we and our customers would have reduced capacity to transport, store or deliver natural gas or NGL products to end use markets or to receive deliveries of mixed NGLs, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect or in operations on third-party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or our gathering systems or processed, fractionated, treated, or stored at our facilities could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our operating results for certain components of our business might fluctuate on a seasonal basis.
Revenues from certain components of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

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

We do not own all of the land on which our pipelines and facilities have been constructed. As such, we are subject to the possibility of increased costs to retain necessary land use. In those instances in which we do not own the land on which our facilities are located, we obtain the rights to construct and operate our pipelines and gathering systems on land owned by third parties and governmental agencies for a specific period of time. In addition, some of our facilities cross Native American lands pursuant to rights-of-way of limited terms. We may not have the right of eminent domain over land owned by Native American tribes. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our business could be negatively impacted as a result of stockholder activism.

In recent years, stockholder activism, including threatened or actual proxy contests, has been directed against numerous public companies, including ours. During the latter part of fiscal year 2016, we were the target of a proxy contest from a stockholder activist, which resulted in our incurring significant costs. If stockholder activists were to again take or threaten to take actions against the Company or seek to involve themselves in the governance, strategic direction or operations of the Company, we could incur significant costs as well as the distraction of management, which could have an adverse effect on our business or financial results. In addition, actions of activist stockholders may cause significant fluctuations in our stock price based on temporary or speculative market perceptions or other factors that do not necessarily reflect the underlying fundamentals and prospects of our business.

Our costs and funding obligations for our defined benefit pension plans and costs for our other postretirement benefit plans are affected by factors beyond our control.
We have defined benefit pension plans covering substantially all of our U.S. employees and other postretirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors that we control, including changes to pension plan benefits, as well as factors outside of our control, such as asset returns, interest rates, and changes in pension laws. Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition and results of operations.

Failure to attract and retain an appropriately qualified workforce could negatively impact our results of operations.
Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract labor may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with projects and ongoing operations. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate the businesses. If we are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.
If there is a determination that the spin-off of WPX Energy, Inc. (WPX) stock to our stockholders is taxable for U.S. federal income tax purposes because the facts, representations or undertakings underlying a U.S. Internal Revenue Service private letter ruling or a tax opinion are incorrect or for any other reason, then we and our stockholders could incur significant income tax liabilities.

In connection with our original separation plan that called for an initial public offering (IPO) of stock of WPX and a subsequent spin-off of our remaining shares of WPX to our stockholders, we obtained a private letter ruling from the IRS and an opinion of our outside tax advisor, to the effect that the distribution by us of WPX shares to our stockholders, and any related restructuring transaction undertaken by us, would not result in recognition for U.S. federal income tax purposes, of income, gain or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the U.S. Internal Revenue Code of 1986, as amended (Code), except for cash payments made to our stockholders in lieu of fractional shares of WPX common stock. In addition, we received an opinion from our outside tax advisor to the effect that the spin-off pursuant to our revised separation plan which was ultimately consummated on December 31, 2011, which did not involve an IPO of WPX shares, would not result in the recognition, for federal income tax purposes, of income, gain, or loss to us or our stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to our stockholders in lieu of fractional shares of WPX. The private letter ruling and opinion have relied on or will rely on certain facts, representations, and undertakings from us and WPX regarding the past and future conduct of the companies’ respective businesses and other matters. If any of these facts, representations, or undertakings are, or become, incorrect or are not otherwise satisfied, including as a result of certain significant changes in the stock ownership of us or WPX after the spin-off, or if the IRS disagrees with any such facts and representations upon audit, we and our stockholders may not be able to rely on the private letter ruling or the opinion of our tax advisor and could be subject to significant income tax liabilities.

Risks Related to Financing Our Business
Downgrades of our credit ratings, which are determined outside of our control by independent third parties, impact our liquidity, access to capital, and our costs of doing business.

Downgrades of our credit ratings increase our cost of borrowing and could require us to provide collateral to our counterparties, negatively impacting our available liquidity. In addition, our ability to access capital markets could continue to be limited by the downgrading of our credit ratings.

Credit rating agencies perform independent analysis when assigning credit ratings. This analysis includes a number of criteria such as, business composition, market, and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are subject to revision or withdrawal at any time by the ratings agencies. As of the date of the filing of this report, we have been assigned an investment-grade credit rating by each of the three credit ratings agencies.

Difficult conditions in the global financial markets and the economy in general could negatively affect our business and results of operations.

Our businesses may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are industrial or economic contraction leading to reduced energy demand and lower prices for our products and services and increased difficulty in collecting amounts owed to us by our customers. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures. In addition, financial markets have periodically been affected by concerns over U.S. fiscal and monetary policies. These concerns, as well as actions taken by the U.S. federal government in response to these concerns, could significantly and adversely impact the global and U.S. economies and financial markets, which could negatively impact us in the manner described above.

Restrictions in our debt agreements and the amount of our indebtedness may affect our future financial and operating flexibility.

Our total outstanding long-term debt (including current portion) as of December 31, 2018, was $22.4 billion.

The agreements governing our indebtedness contain covenants that restrict our and our material subsidiaries' ability to incur certain liens to support indebtedness and our ability to merge or consolidate or sell all or substantially all of our assets in certain circumstances. In addition, certain of our debt agreements contain various covenants that restrict or limit, among other things, our ability to make certain distributions during the continuation of an event of default, the ability of our subsidiaries to incur additional debt, and our, and our material subsidiaries', ability to enter into certain affiliate transactions and certain restrictive agreements. Certain of our debt agreements also contain, and those we enter into in the future may contain, financial covenants, and other limitations with which we will need to comply.

Our debt service obligations and the covenants described above could have important consequences. For example, they could:

- Make it more difficult for us to satisfy our obligations with respect to our indebtedness, which could in turn result in an event of default on such indebtedness;

- Impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes, or other purposes;

- Diminish our ability to withstand a continued or future downturn in our business or the economy generally;

- Require us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, the payments of dividends, general corporate purposes, or other purposes;

- Limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate, including limiting our ability to expand or pursue our business activities and preventing us from engaging in certain transactions that might otherwise be considered beneficial to us.

Our ability to comply with our debt covenants, to repay, extend, or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance. Our ability to refinance existing debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to comply with these covenants, meet our debt service obligations, or obtain future credit on favorable terms, or at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Our failure to comply with the covenants in the documents governing our indebtedness could result in events of default, which could render such indebtedness due and payable. We may not have sufficient liquidity to repay our indebtedness in such circumstances. In addition, cross-default or cross-acceleration provisions in our debt agreements could cause a default or acceleration to have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. For more information regarding our debt agreements, please read Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.

Increases in interest rates could adversely impact our share price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash dividends at our intended levels.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our share price will be impacted by the level of our dividends and implied dividend yield. The dividend yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our shares, and a rising interest rate environment could have an adverse impact on our share price and our ability to issue equity or incur debt for acquisitions or other purposes and to pay cash dividends at our intended levels.

Our hedging activities might not be effective and could increase the volatility of our results.

In an effort to manage our financial exposure related to commodity price and market fluctuations, we have entered, and may in the future enter into contracts to hedge certain risks associated with our assets and operations. In these hedging activities, we have used, and may in the future use, fixed-price, forward, physical purchase, and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. Nevertheless, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist. While we attempt to manage counterparty credit risk within guidelines established by our credit policy, we may not be able to successfully manage all credit risk and as such, future cash flows and results of operations could be impacted by counterparty default.

Risks Related to Regulations

The natural gas sales, transportation, and storage operations of our gas pipelines are subject to regulation by the FERC, which could have an adverse impact on their ability to establish transportation and storage rates that would allow them to recover the full cost of operating their respective pipelines, including a reasonable rate of return.

In addition to regulation by other federal, state, and local regulatory authorities, interstate pipeline transportation and storage service is subject to regulation by the FERC. Federal regulation extends to such matters as:

- Transportation and sale for resale of natural gas in interstate commerce;

- Rates, operating terms, types of services, and conditions of service;

- Certification and construction of new interstate pipelines and storage facilities;

- Acquisition, extension, disposition, or abandonment of existing interstate pipelines and storage facilities;

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- Accounts and records;
- Depreciation and amortization policies;
- Relationships with affiliated companies who are involved in marketing functions of the natural gas business;
- Market manipulation in connection with interstate sales, purchases, or transportation of natural gas.

Regulatory or administrative actions in these areas, including successful complaints or protests against the rates of the gas pipelines, can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs, and otherwise altering the profitability of our pipeline business.

The operation of our businesses might be adversely affected by regulatory proceedings, changes in government regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in the proposal and/or implementation of increased regulations. Such scrutiny has also resulted in various inquiries, investigations, and court proceedings, including litigation of energy industry matters. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

Certain inquiries, investigations, and court proceedings are ongoing. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations, and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines and/or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our results of operations or increase our operating costs in other ways. Current legal proceedings or other matters, including environmental matters, suits, regulatory appeals, and similar matters might result in adverse decisions against us which, among other outcomes, could result in the imposition of substantial penalties and fines and could damage our reputation. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations, including those pertaining to financial assurances to be provided by our businesses in respect of potential asset decommissioning and abandonment activities, might be revised, reinterpreted, or otherwise enforced in a manner which differs from prior regulatory action. New laws and regulations, including those pertaining to oil and gas hedging and cash collateral requirements, might also be adopted or become applicable to us, our customers, or our business activities. If new laws or regulations are imposed relating to oil and gas extraction, or if additional or revised levels of reporting, regulation, or permitting moratoria are required or imposed, including those related to hydraulic fracturing, the volumes of natural gas and other products that we transport, gather, process, and treat could decline, our compliance costs could increase, and our results of operations could be adversely affected.

Our operations are subject to environmental laws and regulations, including laws and regulations relating to climate change and greenhouse gas emissions, which may expose us to significant costs, liabilities, and expenditures that could exceed our expectations.

Our operations are subject to extensive federal, state, tribal, and local laws and regulations governing environmental protection, endangered and threatened species, the discharge of materials into the environment, and the security of industrial facilities. Substantial costs, liabilities, delays, and other significant issues related to environmental laws and regulations are inherent in the gathering, transportation, storage, processing, and treating of natural gas, fractionation, transportation, and storage of NGLs, and crude oil transportation and production handling as well as waste disposal practices and construction activities. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, and delays or denials in granting permits.

Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, for the remediation of contaminated areas and in connection with spills or releases of materials associated with natural gas, oil, and wastes on, under or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage and processing or oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

In addition, climate change regulations and the costs associated with the regulation of emissions of greenhouse gases (GHGs) have the potential to affect our business. Regulatory actions by the Environmental Protection Agency or the passage of new climate change laws or regulations could result in increased costs to operate and maintain our facilities, install new emission controls on our facilities, or administer and manage our GHG compliance program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Climate change and GHG regulation could also reduce demand for our services.

We expect that certain aspects of the Tax Cuts and Jobs Act signed into law on December 22, 2017 (Tax Reform), including regulatory liabilities relating to reduced corporate federal income tax rates, could adversely impact our financial condition and our future financial results.

Tax Reform made significant changes to the U.S. federal income tax rules applicable to both individuals and entities, including among other things, a reduction in corporate federal income tax rates. The rates we charge to our customers are subject to the rate-making policies of the FERC. These policies permit us to include in our cost-of-service an income tax allowance that includes a deferred income tax component. Although we expect the decreased federal income tax rates will require us to return amounts to certain customers through future rates and have recognized a regulatory liability, the details of any regulatory implementation guidance remain uncertain.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Please read “Business” for a description of the location and general character of our principal physical properties. We generally own our facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses, or consents on and across properties owned by others.

Item 3. 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 continuing to work with the agencies to resolve this matter.
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 Transco's Dalton expansion 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 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.
On August 27, 2018, Northwest Pipeline LLC received a Notice of Violation/Cease and Desist Order from the Colorado Department of Public Health & Environment regarding certain alleged violations of the Colorado Water Quality Control Act and its General Permit under the Colorado Discharge Permit System related to its stormwater management practices at two construction sites. The Notice of Violation does not contain an initial penalty assessment. We have responded to the alleged violations and continue to work with the agency to resolve this matter.
Other environmental matters called for by this Item are described under the caption "Environmental Matters" in Note 18 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements included under Part II, Item 8 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 18 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements included under Part II, Item 8 Financial Statements of this report, which information is incorporated by reference into this Item.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

The name, title, age, period of service, and recent business experience of each of our executive officers as of February 21, 2019, are listed below. Williams Partners L.P. merged with ACMP in February 2015 (the ACMP Merger). ACMP was the surviving entity in the ACMP Merger and changed its name to Williams Partners L.P. References in the biographical information below to (a) "Pre-merger WPZ" will mean Williams Partners L.P. prior to the ACMP Merger and (b) "ACMP/WPZ" will refer to both ACMP prior to and after the ACMP Merger, when it changed its name to Williams Partners L.P.

Name and Title	Age	Period of Service	Business Experience in Past Five Years
Alan S. Armstrong	56	2011 to present	Director, Chief Executive Officer, and President, The Williams Companies, Inc.
Director, Chief Executive Officer, and President		2015 to 2018	Chairman of the Board, ACMP/WPZ
		2014 to 2018	Chief Executive Officer, ACMP/WPZ
		2012 to 2018	Director of the general partner, ACMP/WPZ
		2011 to 2015	Chairman of the Board and Chief Executive Officer of the general partner of Pre-merger WPZ
Walter J. Bennett	49	2015 to present	Senior Vice President- West, The Williams Companies, Inc.
Senior Vice President - West		2013 to 2018	Senior Vice President - West of the general partner, ACMP/WPZ
		2017	Director of the general partner, ACMP/WPZ
		2015	Senior Vice President - West of the general partner, Pre-merger WPZ
John D. Chandler	49	2017 to present	Senior Vice President and Chief Financial Officer, The Williams Companies, Inc.
Senior Vice President and Chief Financial Officer		2017 to 2018	Director of the general partner, ACMP/WPZ
		2009 to 2014	Senior Vice President and Chief Financial Officer, Magellan GP, LLC
Debbie Cowan	41	2018 to present	Senior Vice President - Chief Human Resources Officer, The Williams Companies, Inc.
Senior Vice President - Chief Human Resources Officer		2013 to 2018	Global Vice President of Human Resources, Koch Chemical Technology Group, LLC
Micheal G. Dunn	53	2017 to present	Executive Vice President and Chief Operating Officer, The Williams Companies, Inc.
Executive Vice President and Chief Operating Officer		2017 to 2018	Director of the general partner, ACMP/WPZ
		2015 to 2017	President / Executive Vice President, Questar Pipeline / Questar Corporation
		2010 to 2015	President and Chief Executive Officer, PacifiCorp Energy
Scott A. Hallam	42	2019 to present	Senior Vice President - Atlantic-Gulf, The Williams Companies, Inc.
Senior Vice President - Atlantic-Gulf		2017 to 2019	Vice President GM Atlantic-Gulf, The Williams Companies, Inc.
		2015 to 2017	Vice President Northeast OA, The Williams Companies, Inc.
		2013 to 2015	General Manager - Utica, ACMP
John E. Poarch	53		

Senior Vice President - Engineering Services	2017 to present	Senior Vice President - Engineering Services, The Williams Companies, Inc.
	2017	Vice President - Commercial - West, The Williams Companies, Inc.
	2015 to 2017	Vice President - Commercial & Business Development, The Williams Companies, Inc.
	2011 to 2015	General Manager - Eagle Ford, ACMP

Name and Title	Age	Period of Service	Business Experience in Past Five Years
James E. Scheel	54	2014 to present	Senior Vice President - Northeast G&P, The Williams Companies, Inc.
Senior Vice President - Northeast G&P		2015 to 2017	Director of the general partner, ACMP/WPZ
		2012 to 2015	Director of the general partner, Pre-merger WPZ
		2012 to 2014	Director of the general partner, Pre-merger ACMP
		2012 to 2014	Senior Vice President - Corporate Strategic Development, The Williams Companies, Inc.
		2012 to 2014	Senior Vice President - Corporate Strategic Development of the general partner, Pre-merger WPZ
Ted T. Timmermans	62	2005 to present	Vice President, Controller, and Chief Accounting Officer, The Williams Companies, Inc.
Vice President, Controller, and Chief Accounting Officer		2015 to 2018	Vice President, Controller, and Chief Accounting Officer of the general partner, ACMP/WPZ
T. Lane Wilson	52	2018 to present	Senior Vice President and General Counsel, The Williams Companies, Inc.
Senior Vice President and General Counsel		2017 to 2018	Senior Vice President, General Counsel, and Chief Compliance Officer, The Williams Companies, Inc.
		2009 to 2017	United States Magistrate Judge for the Northern District of Oklahoma
Chad J. Zamarin	42	2017 to present	Senior Vice President - Corporate Strategic Development, The Williams Companies, Inc.
Senior Vice President - Corporate Strategic Development		2017 to 2018	Director of the general partner, ACMP/WPZ
		2014 to 2017	President - Pipeline and Midstream, Cheniere Energy
		2011 to 2014	Chief Operating Officer, NiSource Midstream, LLC and NiSource Energy Ventures, LLC

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange under the symbol “WMB.” At the close of business on February 15, 2019, we had 6,780 holders of record of our common stock.

Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg Americas Pipelines Index for the period of five fiscal years commencing January 1, 2014. The Bloomberg Americas Pipelines Index is composed of Enbridge Inc., Kinder Morgan, Inc., TransCanada Corporation, ONEOK, Inc., Pembina Pipeline Corporation, Cheniere Energy, Inc., Targa Resources Corp., Inter Pipeline Ltd., Keyera Corp., Tallgrass Energy L.P., and Williams. The graph below assumes an investment of $100 at the beginning of the period.

	2013	2014	2015	2016	2017	2018
The Williams Companies, Inc.	100.0	121.4	73.8	97.0	98.9	75.3
S&P 500 Index	100.0	113.7	115.2	129.0	157.2	150.3
Bloomberg Americas Pipelines Index	100.0	117.1	64.4	94.5	94.3	80.8

Item 6. Selected Financial Data

The following financial data at December 31, 2018 and 2017, and for each of the three preceding years in the period ended December 31, 2018, should be read in conjunction with the other financial information included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data of this Form 10-K. All other financial data has been prepared from our accounting records.

	2018	2017	2016	2015	2014
	(Millions, except per-share amounts)				
Revenues	$8,686	$8,031	$7,499	$7,360	$7,637
Net income (loss) from continuing operations (1)	193	2,509	(350)	(1,314)	2,335
Amounts attributable to The Williams Companies, Inc.:					
Net income (loss) from continuing operations (1)	(155)	2,174	(424)	(571)	2,110
Diluted earnings (loss) per common share:					
Net income (loss) from continuing operations (1)	(.16)	2.62	(.57)	(.76)	2.91
Total assets at December 31	45,302	46,352	46,835	49,020	50,455
Commercial paper and long-term debt due within one year at December 31	47	501	878	675	802
Long-term debt at December 31	22,367	20,434	22,624	23,812	20,780
Stockholders' equity at December 31 (2)	14,660	9,656	4,643	6,148	8,777
Cash dividends declared per common share	1.360	1.200	1.680	2.450	1.958

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(1) Net income (loss) from continuing operations:

- For 2018 includes a $1.849 billion impairment of certain assets located in the Barnett Shale region, partially offset by a $591 million gain on the sale of our Four Corners area assets, a $141 million gain on the deconsolidation of certain Permian assets, and a $101 million gain from the sale of our Gulf Coast pipeline system assets;
- For 2017 includes a $1.923 billion benefit for income taxes resulting from Tax Reform rate change, a $1.095 billion pre-tax gain on the sale of our Geismar Interest, partially offset by $1.248 billion of pre-tax impairments of certain assets, and $776 million of pre-tax regulatory charges resulting from Tax Reform;
- For 2016 includes an $873 million impairment of certain assets and a $430 million impairment of certain equity-method investments;
- For 2015 includes a $1.4 billion impairment of certain equity-method investments and a $1.1 billion impairment of goodwill;
- For 2014 includes $2.5 billion pre-tax gain recognized as a result of remeasuring to fair value the equity-method investment we held before we acquired a controlling interest in ACMP, $246 million of insurance recoveries related to the 2013 Geismar Incident, and $154 million of cash received related to a contingency settlement. 2014 also includes $78 million of pre-tax equity losses from Bluegrass Pipeline and Moss Lake related primarily to the underlying write-off of previously capitalized project development costs and $76 million of pre-tax acquisition, merger, and transition expenses related to our acquisition of ACMP.

(2) Stockholders' equity at December 31:

- The increase in 2018 reflects our merger with WPZ;
- The increase in 2017 includes our issuance of common stock as part of our Financial Repositioning.

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Item 7. 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 business. Our operations are located in the United States.

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, oil and natural gas, as well as storage facilities.

Prior to our merger with Williams Partners L.P., our previously consolidated master limited partnership, in August 2018, 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 4 – Variable Interest Entities of Notes to Consolidated Financial Statements).
- West is comprised of our interstate natural gas pipeline, Northwest Pipeline, and our gathering, processing, and treating operations in Colorado, Wyoming, and 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 50 percent equity-method investment in RMM, a 15 percent equity-method investment in Brazos Permian II, and our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-

Continent region (see Note 6 – Investing Activities of Notes to Consolidated Financial Statements). West also included our former natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).

- Other includes our previously owned operations, including an 88.5 percent undivided interest in an olefins production facility in Geismar, Louisiana, which was sold in July 2017 (see Note 3 – Divestitures of Notes to Consolidated Financial Statements), and a refinery grade propylene splitter in the Gulf region, which was sold in June 2017. This segment also included our previously owned Canadian assets, which included an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility at Redwater, Alberta. In September 2016, these Canadian operations were sold. Other also includes minor business activities that are not operating segments, as well as corporate operations.

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Part II, Item 8 of this report.

Dividends

In December 2018, we paid a regular quarterly dividend of $0.34 per share. On February 20, 2019, our board of directors approved a regular quarterly dividend of $0.38 per share payable on March 25, 2019.

Overview

Net income (loss) attributable to The Williams Companies, Inc., for the year ended December 31, 2018, decreased by $2.329 billion compared to the year ended December 31, 2017, reflecting a $2.112 billion increase to the provision for income taxes driven by the absence of a 2017 benefit resulting from Tax Reform and a $159 million decrease in operating income. The decrease in operating income reflects an increase of $667 million in Impairment of certain assets and $403 million in lower gains from the sale of certain assets. These unfavorable changes were partially offset by the absence of $674 million in regulatory charges resulting from Tax Reform in 2017, and a $190 million increase in service revenues primarily resulting from expansion projects placed into service in 2017 and 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 noncash equity transaction. Williams continued as the surviving entity. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements.)

FERC Income Tax Policy Revision

On March 15, 2018, the FERC issued a revised policy statement (the revised policy 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 revised policy 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. 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 that 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 (i) the reduction in the corporate income tax is already addressed in Northwest Pipeline's 2017 rate settlement, and (ii) as discussed above, the WPZ Merger allows for the continued recovery of income tax allowances in Northwest Pipeline's rates. The FERC agreed and granted Northwest Pipeline's petition for waiver on November 19, 2018. On October 11, 2018 and December 6, 2018, Discovery Gas Transmission, LLC and Pine Needle LNG Company, LLC, respectively, filed their Form 501-Gs, including explanations as to why no adjustments to rates are needed.

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.

Revenue Recognition

As a result of the adoption of Accounting Standards Update 2014-09, Revenues from Contracts with Customers (ASC 606) in January 2018, 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 Operations. 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 Operations. 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 Operations. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies 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.

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 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 has since increased to 50 percent at December 31, 2018, based on additional capital contributions made since the initial purchase. This investment is reported in the West segment.

Sale of Four Corners Assets

In October 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. These assets were designated as held for sale during the third quarter of 2018. As a result of this sale, we recorded a gain of approximately $591 million within the West segment in the fourth quarter of 2018 (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).

Sale of Gulf Coast Pipeline Systems

In November 2018, we completed the sale of certain assets and operations located in the Gulf Coast area for $177 million in cash. These assets were designated as held for sale during the third quarter of 2018. As a result of this sale, we recorded a gain of approximately $101 million in the fourth quarter of 2018, consisting of $81 million in our Atlantic-Gulf segment and $20 million in Other (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).

Brazos Permian II Equity-Method Investment

In December 2018, we entered into a joint venture partnership in the Delaware basin. Under the terms of the agreement, we contributed the majority of our existing Delaware basin assets in the West segment and $27 million in cash to the partnership in exchange for a 15 percent interest. Our partner operates the partnership, which consists of approximately 725 miles of gas gathering pipelines, 260 MMcf/d of natural gas processing, 75 miles of crude oil gathering pipelines, and 75 thousand barrels of oil storage. The partnership anticipates processing capacity in the Delaware basin to reach 460 MMcf/d and will be supported by over 500,000 acres of long-term dedications from major and independent oil and gas producers. We recorded our interest in the partnership as an equity-method investment and recognized a gain on the deconsolidation of our contributed assets of $141 million (see Note 6 – Investing Activities of Notes to Consolidated Financial Statements).

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

Gulf Connector

In January 2019, the Gulf Connector project was placed into service. This project expanded Transco's 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. The project increased capacity by 475 Mdth/d.

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. In total, the 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 19 percent higher in 2018 compared to 2017 primarily due to a 22 percent increase in realized per-unit non-ethane prices and an approximate 9 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 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.

Our business plan for 2019 includes a continued focus on growing our fee-based businesses, executing growth projects, including through joint ventures, and accomplishing cost discipline initiatives to ensure operations support our strategy. We anticipate operating results will increase through organic business growth driven by continued expansion in the Northeast region and Transco expansion projects.

Our growth capital and investment expenditures in 2019 are expected to be in a range from $2.7 billion to $2.9 billion. Growth capital spending in 2019 includes Transco expansions, all of which are fully contracted with firm transportation agreements, and continuing to develop our gathering and processing infrastructure in the Northeast G&P and West segments. 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 expansion projects 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 2019, current forward market prices indicate oil, natural gas, and NGL prices are expected to be lower compared to 2018. We continue to address certain pricing risks through the utilization of commodity hedging strategies.

In 2019, our operating results are expected to include increases from our regulated Transco fee-based business, primarily related to projects recently placed in-service. For our non-regulated businesses, we anticipate increases in fee-based revenue in the Northeast G&P segment associated with recent expansion projects, partially offset with a decrease in the West segment primarily due to recent asset divestitures. We expect overall gathering and processing volumes to grow in 2019 for our continuing businesses and anticipate an increase in our equity earnings primarily associated with new investments. Additionally, we believe general and administrative expenses will be slightly lower due to recent asset divestitures and the effect of the WPZ merger.

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;
- Unexpected changes in customer drilling and production activities, which could negatively impact gathering and processing volumes;
- 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;
- Other risks set forth under Part I, Item 1A. Risk Factors in this report.

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 up to 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. On November 5, 2018, the FERC granted our request for an extension of time to December 2, 2020, to construct and place into service the Constitution pipeline. And, in September 2018, we filed a petition with the D.C. Circuit for review of the FERC's denial of our petition for declaratory order. (See Note 4 – Variable Interest Entities of Notes to Consolidated Financial Statements.)

Gateway

In December 2018, we received approval from 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.

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.

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 completed 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.

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 60 miles of gathering pipelines and compression, and modifications to existing treating and processing facilities. We plan to place the first phase of the project into service during the first quarter of 2019.

Project Bluestem

We are expanding our presence in the Mid-Continent region through building a 188-mile pipeline from our fractionator in Conway, Kansas to an interconnect with a third-party NGL pipeline system in Oklahoma, providing us with firm access to Mt. Belvieu pricing. As part of the project, the third-party intends to construct a 110-mile pipeline extension of their existing NGL pipeline system that will have an initial capacity of 120 Mbbls/d. Further, we will have an option to purchase a 20 percent equity interest in a Mt. Belvieu fractionation train developed by the third party. The pipeline and extension projects are expected to be placed into service during the first quarter of 2021.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit cost and obligations for these plans are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, cash balance interest crediting rate, expected rate of compensation increase, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute cost and the benefit obligations are shown in Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements.

The following table presents the estimated increase (decrease) in net periodic benefit cost and obligations resulting from a one-percentage-point change in the specific assumption.

	Benefit Cost		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$(7)	$ 8	$(101)	$ 119
Expected long-term rate of return on plan assets	(12)	12	—	—
Cash balance interest crediting rate	16	(13)	76	(64)
Rate of compensation increase	1	(1)	5	(4)
Other postretirement benefits:				
Discount rate	1	1	(19)	23
Expected long-term rate of return on plan assets	(2)	2	—	—

Our expected long-term rates of return on plan assets, as determined at the beginning of each fiscal year, are based on the average rate of return expected on the funds invested in the plans. We determine our long-term expected rates of return on plan assets using our expectations of capital market results, which include an analysis of historical results as well as forward-looking projections. These capital market expectations are based on a period of at least 10 years and take into account our investment strategy and mix of assets. We develop our expectations using input from our third-party independent investment consultant. The forward-looking capital market projections start with current conditions of interest rates, equity pricing, economic growth, and inflation and those are overlaid with forward looking projections of normal inflation, growth, and interest rates to determine expected returns. The capital market return projections for specific asset classes in the investment portfolio are then applied to the relative weightings of the asset classes in the investment portfolio. The resulting rates are an estimate of future results and, thus, likely to be different than actual results.

Our expected long-term rate of return on plan assets used for our pension plans was 5.34 percent in 2018. The 2018 actual return on plan assets for our pension plans was a loss of approximately 3.6 percent. The 10-year average rate of return on pension plan assets through December 2018 was approximately 8.3 percent. While the 2018 investment performance was less than our expected rates of return, the expected rates of return on plan assets are long-term in nature and are not significantly impacted by short-term market performance. Changes to our asset allocation would also impact the expected rates of return.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related cost. The discount rates for our pension and other postretirement benefit plans are determined separately based on an approach specific to our plans and their respective expected benefit cash flows as described in Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies and Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements. Our discount rate assumptions are impacted by changes in general economic and market conditions that affect interest rates on long-term, high-quality debt securities as well as by the duration of our plans' liabilities.

The cash balance interest crediting rate assumption represents the average long-term rate by which the pension plans' cash balance accounts are expected to grow. Interest on the cash balance accounts is based on the 30-year U.S. Treasury securities rate and is credited to the accounts quarterly. An increase in this rate causes the pension obligation and cost to increase.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and cost to increase.

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Property, Plant, and Equipment and Other Identifiable Intangible Assets

We evaluate our property, plant, and equipment and other identifiable intangible assets for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred, and we may apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

Certain of our contractual gathering rates, primarily those in the Barnett Shale, are based on a percentage of the New York Mercantile Exchange (NYMEX) natural gas prices. During the fourth quarter of 2018, we determined there was a sustained decline in the forward price curves for natural gas. During this same period, a large producer customer in the Barnett Shale removed their remaining drilling rig. These factors gave rise to an impairment evaluation of these assets. The historical carrying value of our Barnett assets was initially recorded based on the estimated fair value during the third quarter of 2014 in conjunction with the acquisition of ACMP.

Our evaluation incorporated management’s projections of future drilling levels and gathering rates, taking into consideration the information noted above as well as recently available information regarding producer drilling cost assumptions in this basin. The resulting estimate of future undiscounted cash flows was less than our carrying value, necessitating the estimation of the fair value of these assets. In arriving at the fair value, we utilized an income approach with a discount rate of 8.5 percent, reflecting an estimated cost of capital and risks associated with the underlying assets. As a result, we recorded an impairment charge of $1.849 billion to reduce the carrying value to our estimate of fair value. A one-percentage-point increase in the discount rate would decrease our estimate of fair value by approximately $37 million.

Judgments and assumptions are inherent in estimating undiscounted future cash flows, fair values, and the probability-weighting of possible outcomes. The use of alternate judgments and assumptions could result in a different determination affecting the consolidated financial statements.

Constitution Pipeline Capitalized Project Costs

As of December 31, 2018, Property, plant, and equipment – net 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 at 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. Subsequently, there have been no events or changes in circumstances that impact our conclusion. 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.

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. Due to 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. As a result, we established regulatory liabilities during 2017 and at December 31, 2018, these liabilities total $657 million. 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.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2018. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2018	$ Change from 2017*	% Change from 2017*	2017	$ Change from 2016*	% Change from 2016*	2016
	(Millions)						
Revenues:							
Service revenues	$5,502	+190	+4 %	$5,312	+141	+3 %	$5,171
Service revenues - commodity consideration	400	+400	NM	—	—	NM	—
Product sales	2,784	+65	+2 %	2,719	+391	+17 %	2,328
Total revenues	8,686			8,031			7,499
Costs and expenses:							
Product costs	2,707	-407	-18 %	2,300	-575	-33 %	1,725
Processing commodity expenses	137	-137	NM	—	—	NM	—
Operating and maintenance expenses	1,507	+69	+4 %	1,576	+16	+1 %	1,592
Depreciation and amortization expenses	1,725	+11	+1 %	1,736	+27	+2 %	1,763
Selling, general, and administrative expenses	569	+25	+4 %	594	+128	+18 %	722
Impairment of certain assets	1,915	-667	-53 %	1,248	-375	-43 %	873
Gain on sale of certain assets	(692)	-403	-37 %	(1,095)	+1,095	NM	—
Regulatory charges resulting from Tax Reform	(17)	+691	NM	674	-674	NM	—
Other (income) expense – net	67	+4	+6 %	71	+64	+47 %	135
Total costs and expenses	7,918			7,104			6,810
Operating income (loss)	768			927			689
Equity earnings (losses)	396	-38	-9 %	434	+37	+9 %	397
Impairment of equity-method investments	(32)	-32	NM	—	+430	+100 %	(430)
Other investing income (loss) – net	219	-63	-22 %	282	+219	NM	63
Interest expense	(1,112)	-29	-3 %	(1,083)	+96	+8 %	(1,179)
Other income (expense) – net	92	+117	NM	(25)	-110	NM	85
Income (loss) before income taxes	331			535			(375)
Provision (benefit) for income taxes	138	-2,112	NM	(1,974)	+1,949	NM	(25)
Net income (loss)	193			2,509			(350)
Less: Net income (loss) attributable to noncontrolling interests	348	-13	-4 %	335	-261	NM	74
Net income (loss) attributable to The Williams Companies, Inc.	$(155)			$2,174			$(424)

* + = 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.

2018 vs. 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 and

Ohio River Supply Hub. These increases are partially offset by a change in the rate of deferred revenue recognition resulting from implementing ASC 606, reduced revenues from our Four Corners area operations that were sold in October 2018, a reduction of rates resulting from a Northwest Pipeline rate case settlement, and a decrease following the Jackalope deconsolidation.

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 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies 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, which are offset in Product costs, and higher sales from the production of our equity NGLs, reflecting higher NGL prices. These increases are partially offset by the absence of $269 million in olefin sales revenue associated with our former Gulf Olefins operations in 2017.

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 costs due to the sale of our former Gulf Olefins 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 $80 million of costs associated with our former Gulf Olefins and Four Corners area operations.

Depreciation and amortization expenses decreased primarily due to the absence of our former Gulf Olefins and Four Corners area 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, and Financial Repositioning costs incurred in 2017, $25 million in reduced costs associated with our former Gulf Olefins and Four Corners area operations, and ongoing cost containment efforts. These decreases are partially offset by a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (see Note 15 – Stockholders' Equity of Notes to Consolidated Financial Statements) and fees associated with the WPZ Merger.

The unfavorable change in Impairment of certain assets includes 2018 impairments on certain assets in the Barnett Shale region and certain idle pipelines, partially offset by the absence of 2017 impairments associated with certain assets in the Mid-Continent, Marcellus South, and Houston Ship Channel areas (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements).

The unfavorable change in Gain on sale of certain assets reflects the absence of a gain recognized on the sale of our Geismar Interest in July 2017, partially offset by gains recognized on the sales of our Four Corners area in October 2018 and our Gulf Coast pipeline systems in December 2018 (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).

Regulatory charges resulting from Tax Reform relates to the 2017 recognition of regulatory liabilities for the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies 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, substantially 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 charges establishing a regulatory liability associated with a decrease in Northwest Pipeline's estimated deferred state income tax rate following the WPZ Merger.

Operating income (loss) changed unfavorably primarily due to higher impairments of assets, lower gains on sales of assets, and the absence of operating income associated with our former Gulf Olefins and Four Corners area operations, partially offset by the absence of regulatory charges resulting from Tax Reform, higher Service revenues primarily from expansion projects, and an increase in NGL margins.

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 and the deconsolidation of our Jackalope interest, which is now accounted for as an equity-method investment beginning in the second quarter of 2018.

The Impairment of equity-method investments in 2018 reflects an impairment related to our investment in UEOM.

Other investing income (loss) – net reflects the absence of the gain on disposition of our investments in DBJV and Ranch Westex JV LLC in 2017, partially offset by gains on the 2018 deconsolidations of certain Permian basin assets and of our interest in Jackalope. (See Note 6 – Investing Activities of Notes to Consolidated Financial Statements.)

Interest expense increased primarily due to an increase in other financing obligations associated with Transco's Dalton and Atlantic Sunrise projects, as well as expense related to the deemed financing component of certain contract liabilities resulting from our implementation of ASC 606 in 2018, offset by lower interest rates on our outstanding debt in 2018 and lower borrowings on our credit facilities in 2018. (See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)

Other income (expense) – net below Operating income (loss) changed favorably primarily due to a decrease in charges reducing regulatory assets related to deferred taxes on the allowance for funds used during construction (AFUDC) resulting from Tax Reform, an increase in equity AFUDC, and a lower settlement charge from the pension early payout program, partially offset by a 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 7 – Other Income and Expenses of Notes to Consolidated Financial Statements.)

Provision (benefit) for income taxes changed unfavorably primarily due to the absence of a $1.923 billion tax provision benefit associated with Tax Reform and releasing a $127 million valuation allowance in 2017. The unfavorable change also reflects a $105 million valuation allowance in 2018 associated with certain foreign tax credits. See Note 8 – 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 unfavorable change in Net income (loss) attributable to noncontrolling interests is primarily related to WPZ, reflective of both our acquisition of the publicly held interests in WPZ associated with the WPZ Merger and a fourth quarter 2017 net loss incurred by WPZ, partially offset by lower operating results at Gulfstar.

2017 vs. 2016

Service revenues increased due to higher transportation fee revenues at Transco and in the eastern Gulf reflecting expansion projects placed in-service in 2016 and 2017; partially offset by a decrease in gathering, processing, and fractionation revenue including lower rates, primarily in the Barnett Shale region associated with the restructuring of contracts in the fourth quarter of 2016; lower volumes in the western regions, driven by natural declines and extreme weather conditions in the Rocky Mountains in 2017; and the sale of our former Canadian and Gulf Olefins operations.

Product sales increased primarily due to higher marketing revenues reflecting significantly higher prices and volumes. Revenues from the sale of our equity NGLs increased primarily due to higher non-ethane NGL prices, partially offset by lower volumes. These increases were partially offset by lower olefin production sales due to lower volumes resulting from the sale of our former Gulf Olefins and Canadian operations.

The increase in Product costs is primarily due to the same factors that increased marketing sales, partially offset by lower olefin feedstock purchases associated with the sale of our Gulf Olefins and Canadian operations.
Operating and maintenance expenses decreased primarily due to the absence of costs associated with our former Canadian and Gulf Olefins operations and lower labor-related costs resulting from our workforce reductions that occurred late in first-quarter 2016, and ongoing cost containment efforts, partially offset by higher pipeline integrity testing and general maintenance at Transco.
Depreciation and amortization expenses decreased primarily due to the absence of our former Canadian and Gulf Olefins operations, partially offset by new assets placed in-service.
Selling, general, and administrative expenses decreased primarily due to the absence of certain project development costs associated with the Canadian PDH facility that were expensed in 2016, lower labor-related costs resulting from our workforce reductions that occurred late in first-quarter 2016, ongoing cost containment efforts, lower strategic development costs, and the absence of costs associated with our former Canadian and Gulf Olefins operations. These decreases were partially offset by higher severance and organizational realignment costs in 2017 (see Note 7 – Other Income and Expenses of Notes to Consolidated Financial Statements).
The unfavorable change in Impairment of certain assets reflects 2017 impairments of certain gathering operations in the Mid-Continent and Marcellus South regions, certain NGL pipeline assets, and an olefins pipeline project in the Gulf coast region. These 2017 impairments are partially offset by the absence of 2016 impairments of our former Canadian operations and certain Mid-Continent assets (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements).
The Gain on sale of certain assets reflects the gain recognized on the sale of our Geismar Interest in July 2017. (See Note 3 – Divestitures of Notes to Consolidated Financial Statements.)
Regulatory charges resulting from Tax Reform relates to the recognition of regulatory liabilities for the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements.)
The favorable change in Other (income) expense – net within Operating income (loss) includes the absence of the 2016 loss on the sale of our Canadian operations, gains from certain contract settlements and terminations in 2017, a gain on the sale of our RGP Splitter in 2017, and the absence of an unfavorable change in foreign currency exchange associated with our former Canadian operations. These favorable changes are partially offset by additional expense associated with an annual revision to the ARO liability, accrual of additional expenses in 2017 related to the Geismar Incident, as well as the absence of a gain in first-quarter 2016 associated with the sale of unused pipe.
Operating income (loss) changed favorably primarily due to the Gain on sale of certain assets, the absence of the 2016 impairments of certain Mid-Continent assets and our former Canadian operations, higher service revenues primarily from expansion projects placed in-service in 2016 and 2017, the absence of expensed Canadian PDH facility project development costs in 2016, as well as ongoing cost containment efforts, including workforce reductions in first-quarter 2016. Operating income (loss) also improved due to the absence of a 2016 loss on the sale of our Canadian operations, the absence of an operating loss associated with our former Canadian operations, gains from certain contract settlements and the sale of our RGP Splitter. These favorable changes were partially offset by 2017 impairments of certain gathering operations in the Mid-Continent and Marcellus South regions and certain NGL pipeline assets, and regulatory charges resulting from Tax Reform, as well as the absence of operating income associated with our former Gulf Olefins operations.
The favorable change in Equity earnings (losses) is due to an increase in ownership of our Appalachia Midstream Investments and improved results at Aux Sable due to favorable pricing and higher volumes, partially offset by lower UEOM results driven by lower processing volumes from the Utica gathering system and lower Discovery results due to lower volumes.

The decrease in Impairment of equity-method investments reflects the absence of 2016 impairment charges associated with our Appalachia Midstream Investments, DBJV, Laurel Mountain, and Ranch Westex equity-method investments. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Other investing income (loss) – net reflects the gain on disposition of our investments in DBJV and Ranch Westex JV LLC in 2017, partially offset by the absence of interest income received in 2016 associated with a receivable related to the sale of certain former Venezuelan assets and the absence of a 2016 gain on the sale of an equity-method investment interest in a gathering system that was part of our Appalachia Midstream Investments. (See Note 6 – Investing Activities of Notes to Consolidated Financial Statements.)

Interest expense decreased primarily due to lower Interest incurred primarily attributable to debt retirements in 2017 and lower borrowings on our credit facilities in 2017. (See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)

Other income (expense) – net below Operating income (loss) changed unfavorably primarily due to charges reducing regulatory assets related to deferred taxes on equity funds used during construction (AFUDC) resulting from Tax Reform and a settlement charge from a pension early payout program (see Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements), partially offset by a net gain on early debt retirements in 2017, and other favorable changes related to AFUDC. (See Note 7 – Other Income and Expenses of Notes to Consolidated Financial Statements.)

Provision (benefit) for income taxes changed favorably primarily due to a reduction in the federal statutory rate from 35 percent to 21 percent with the enactment of Tax Reform. The remeasurement of our existing deferred tax assets and liabilities at the reduced rate resulted in the recognition of a net income tax provision benefit of $1.923 billion. Adjustments within this provision benefit are considered provisional and are potentially subject to change in the future. See Note 8 – 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 unfavorable change in Net income (loss) attributable to noncontrolling interests is primarily due to the impact of decreased income allocated to us driven by the permanent waiver of IDRs and higher operating results at WPZ, partially offset by a decrease in the ownership of the noncontrolling interests. Both the permanent waiver of IDRs and the change in ownership are associated with the first-quarter 2017 Financial Repositioning (see Note 1 – General, Description of Business, and Basis of Presentation of Notes to Consolidated Financial Statements). In addition, improved results in our Gulfstar operations also contributed to the increase in Net income (loss) attributable to noncontrolling interests, partially offset by lower results for our Cardinal gathering system.

Year-Over-Year Operating Results – Segments

We evaluate segment operating performance based upon Modified EBITDA. Note 19 – 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.

Northeast G&P

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Service revenues	$976	$872	$870
Service revenues - commodity consideration	20	—	—
Product sales	287	291	162
Segment revenues	1,283	1,163	1,032
Product costs	(289)	(286)	(159)
Processing commodity expenses	(9)	—	—
Other segment costs and expenses	(392)	(386)	(364)
Impairment of certain assets	—	(124)	(13)
Proportional Modified EBITDA of equity-method investments	493	452	357
Northeast G&P Modified EBITDA	$1,086	$819	$853

2018 vs. 2017

Northeast G&P Modified EBITDA increased primarily due to the absence of Impairment of certain assets in 2017, and higher Service revenues and Proportional Modified EBITDA of equity-method investments.

Service revenues increased due to:

- A $65 million increase in gathering fee revenues at Susquehanna Supply Hub due to 13 percent higher gathering volumes reflecting increased customer production;
- A $24 million increase at Ohio River Supply Hub reflecting higher gathering volumes due to increased customer production;
- An $11 million increase in Utica gathering fee revenues reflecting higher rates and volumes.

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 decreased primarily due to $31 million lower marketing sales, driven by lower non-ethane volumes and prices. The changes in marketing revenues are offset by similar changes in marketing purchases, reflected above as Product costs. The decrease in Product sales is partially offset by $21 million in higher system management gas sales. System management gas sales are offset in Product costs and therefore have no impact on Modified EBITDA.

Impairment of certain assets reflects the absence of a $115 million impairment of certain gathering operations in the Marcellus South region in 2017.

Proportional Modified EBITDA of equity-method investments increased primarily due to a $33 million increase at Appalachia Midstream Investments reflecting our increased ownership acquired in late first-quarter 2017 and higher volumes. Improvements at Aux Sable and Caiman II also contributed to the increase.

2017 vs. 2016

Northeast G&P Modified EBITDA decreased primarily due to higher Impairment of certain assets and Other segment costs and expenses, partially offset by higher Proportional Modified EBITDA of equity-method investments.

Service revenues increased slightly reflecting:

- A $38 million increase in gathering fee revenue at Susquehanna Supply Hub driven by 11 percent higher gathered volumes reflecting increased customer production;
- A $23 million increase in fee revenue at Ohio Valley Midstream reflecting the absence of shut-in volumes from the first half of 2016, as well as new production coming online;
- A $56 million decrease in Utica gathering fee revenues primarily due to 14 percent lower gathered volumes driven by natural declines in the wet gas areas, partially offset by higher volumes from new development in the dry gas areas.

Product sales increased primarily due to higher non-ethane and ethane prices and higher non-ethane volumes within our marketing activities. The changes in marketing revenues are offset by similar changes in marketing purchases, reflected above as Product costs.

Other segment costs and expenses increased due to a $31 million increase in operating and maintenance expenses primarily resulting from higher costs related to various maintenance expenses and ad valorem taxes, and $7 million related to a settlement charge from a pension early payout program (see Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements). These increases are partially offset by $16 million lower general and administrative expenses primarily due to a reduced share of allocated support costs, ongoing cost containment efforts, and 2016 workforce reductions.

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

Proportional Modified EBITDA of equity-method investments changed favorably primarily due to a $100 million increase at Appalachia Midstream Investments reflecting our increased ownership acquired late in the first quarter of 2017 and higher gathering volumes reflecting the absence of shut-in volumes from 2016 and increased customer production, a $20 million increase at Aux Sable due to increased customer production and the absence of the $9 million impairment in 2016, an $8 million increase at Laurel Mountain Midstream associated with higher gathering revenue due to higher rates reflecting higher natural gas prices, partially offset by a $34 million decrease at UEOM driven by lower processing volumes from the wet gas areas of the Utica gathering system as noted above.

Atlantic-Gulf

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Service revenues	$2,509	$2,239	$1,998
Service revenues - commodity consideration	59	—	—
Product sales	435	484	450
Segment revenues	3,003	2,723	2,448
Product costs	(438)	(437)	(405)
Processing commodity expenses	(16)	—	—
Other segment costs and expenses	(799)	(819)	(707)
Impairment of certain assets	—	—	(2)
Gain on sale of certain assets	81	—	—
Regulatory charges resulting from Tax Reform	9	(493)	—
Proportional Modified EBITDA of equity-method investments	183	264	287
Atlantic-Gulf Modified EBITDA	$2,023	$1,238	$1,621
NGL margin	$39	$41	$38

2018 vs. 2017

Atlantic-Gulf Modified EBITDA increased primarily due to the absence of regulatory charges associated with the impact of Tax Reform at Transco, higher Service revenues, and a 2018 Gain on sale of certain assets; partially offset by lower Proportional Modified EBITDA of equity-method investments.

Service revenues increased primarily due to a $253 million increase in Transco's natural gas transportation fee revenues primarily due to a $241 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 $90 million decrease in commodity marketing revenues driven by a $149 million decrease in crude oil revenues as this activity is now presented on a net basis within Product costs in conjunction with the adoption of ASC 606, partially offset by a $59 million increase in NGL marketing revenues primarily reflecting 20 percent higher non-ethane prices;
- A $14 million decrease in revenues associated with our equity NGLs, as further described below as part of our commodity product margins;
- A $57 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 slightly increased primarily due to a $59 million increase in system management gas costs (substantially 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 an $87 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 $17 million increase in Transco's equity AFUDC as a result of projects placed in service in 2018.

Gain on sale of certain assets reflects an $81 million gain from the sale of our Gulf Coast pipeline system assets in fourth quarter 2018.

The decrease in Regulatory charges resulting from Tax Reform reflects the absence of $493 million of regulatory charges in 2017 associated with the impact of Tax Reform at Transco (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements).

The decrease in Proportional Modified EBITDA of equity-method investments is due to an $89 million decrease at Discovery, primarily related to a $76 million decrease associated with production ending on certain wells.

2017 vs. 2016

Atlantic-Gulf Modified EBITDA decreased primarily due to regulatory charges associated with the impact of Tax Reform at our regulated entities, higher Other segment costs and expenses, and lower Proportional Modified EBITDA from Discovery, partially offset by higher Service revenues.

Service revenues increased primarily due to:

- A $135 million increase in Transco's natural gas transportation fee revenues primarily due to a $150 million increase associated with expansion projects placed in-service in 2016 and 2017, partially offset by lower volume-based transportation services revenues;
- A $103 million increase in eastern Gulf Coast region fee revenues primarily related to the impact of new volumes at Gulfstar One related to the Gunflint expansion placed in-service in the third quarter of 2016, the absence of the temporary shut-down and subsequent ramp-up of Gulfstar One in the second and third quarters of 2016 to tie-in Gunflint, and the absence of producers' operational issues in the Tubular Bells field during the first quarter of 2016, partially offset by lower volumes as a result of a temporary increase in 2016 due to disrupted operations of a competitor;
- A $15 million increase in Transco's storage revenue primarily related to the absence of an accrual for potential refunds associated with a ruling received in certain rate case litigation in 2016;
- A $15 million decrease in western Gulf Coast region fee revenues due to lower volumes primarily associated with producer maintenance.

Product sales increased primarily due to:

- A $31 million increase in NGL and crude oil marketing revenues primarily due to a $72 million increase driven by higher prices, partially offset by a $41 million decrease driven by lower volumes. Average realized non-ethane prices were 47 percent higher and average realized crude prices were 18 percent higher. Non-ethane volumes were 16 percent lower and crude volumes were 13 percent lower driven by shut-ins of certain wells behind Devils Tower as a result of production issues and temporary hurricane-related shut-ins. (Increases in marketing revenues are substantially offset by higher Product costs);

- A $12 million increase in system management gas sales from Transco. System management gas sales are offset in Product costs and, therefore, have no impact on Modified EBITDA;
- A $5 million decrease in revenues associated with our equity NGLs due to a $19 million decrease driven by lower volumes, partially offset by a $14 million increase driven by higher prices. Realized non-ethane prices increased by 32 percent. Non-ethane volumes decreased by 31 percent primarily as a result of a temporary increase in 2016 due to disrupted operations of a competitor.

Product costs increased primarily due to:

- A $28 million increase in marketing purchases (more than offset in Product sales);
- A $12 million increase in system management gas costs (offset in Product sales);
- An $8 million decrease in natural gas purchases associated with the production of equity NGLs primarily due to lower volumes.

Other segment costs and expenses increased primarily due to $89 million higher operating costs, primarily associated with Transco pipeline integrity testing and general maintenance, a $17 million increase in expense associated with an annual revision to the ARO liability, $9 million of higher general and administrative costs due to an increased share of allocated support costs, and a $15 million expense in 2017 related to a settlement charge from a pension early payout program (see Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements). These increases are partially offset by a $14 million favorable change in equity AFUDC associated with an increase in Transco's capital spending, which is offset by an $8 million decrease in Constitution's equity AFUDC. Other favorable changes include $12 million lower project development costs at Constitution and favorable impacts related to gains on asset retirements.

Regulatory charges resulting from Tax Reform reflects $493 million of regulatory charges associated with the impact of Tax Reform at Transco (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements).

The decrease in Proportional Modified EBITDA of equity-method investments includes a $12 million decrease from Discovery, a $7 million decrease in Cardinal Pipeline Company, LLC and a $5 million decrease in Pine Needle LNG Company, LLC. The decrease in Discovery is primarily associated with lower fee revenue driven by significant production issues at certain wells, higher turbine maintenance expenses, temporary hurricane-related shut-ins, and maintenance on the Keathley Canyon connector pipeline. The decrease in Cardinal Pipeline Company, LLC and Pine Needle LNG Company, LLC is primarily due to $11 million of regulatory charges associated with the impact of Tax Reform.

West

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Service revenues	$2,085	$2,246	$2,328
Service revenues – commodity consideration	321	—	—
Product sales	2,448	2,013	1,380
Segment revenues	4,854	4,259	3,708
Product costs	(2,448)	(1,842)	(1,256)
Processing commodity expenses	(116)	—	—
Other segment costs and expenses	(825)	(832)	(918)
Impairment of certain assets	(1,849)	(1,032)	(100)
Gain on sale of certain assets	591	—	—
Regulatory charges resulting from Tax Reform	7	(220)	—
Proportional Modified EBITDA of equity-method investments	94	79	110
West Modified EBITDA	$308	$412	$1,544
NGL margin	$194	$154	$112

2018 vs. 2017

West Modified EBITDA decreased primarily due to the increase in Impairment of certain assets and lower Service revenues. These decreases were partially offset by the Gain on sale of certain assets in 2018, the absence of regulatory charges associated with the impact of Tax Reform, and higher NGL margins driven by higher NGL prices and lower realized natural gas prices, partially offset by lower NGL volumes.

Service revenues decreased primarily due to:

- A $64 million decrease primarily associated with implementing the new revenue guidance under ASC 606 including a $118 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, partially offset by a $54 million increase related to other deferred revenue amortization primarily in the Permian basin;
- A $42 million decrease associated with the sale of our Four Corners area assets in October 2018;
- A $30 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 $29 million decrease following the Jackalope deconsolidation in second quarter 2018;
- A $15 million decrease driven by lower gathering volumes primarily in the Eagle Ford Shale, Barnett Shale, and Mid-Continent regions, partially offset by higher volumes in the Niobrara (prior to the Jackalope deconsolidation), Piceance, and Permian regions;
- A $21 million increase associated with higher gathering and processing rates in the Piceance region driven by higher NGL prices as well as higher average gathering and processing rates across most other areas, partially offset by lower contract rates primarily in the Haynesville Shale 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

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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 $373 million increase in marketing revenues primarily due to increases in realized NGL prices including a 14 percent increase in average non-ethane per-unit sales prices and a 25 percent increase in ethane prices, in addition to a 15 percent increase in ethane volumes (more than offset by higher Product costs);
- A $47 million increase associated with sales of our equity NGLs, as further described below as part of our commodity product margins;
- An $18 million increase in system management gas sales due to a change in presentation in accordance with ASC 606, which are more than offset in Product costs and, therefore, have little 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 $381 million increase in marketing purchases (substantially offset in Product sales), a $19 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 $40 million increase in NGL product margins partially offset by an $8 million decrease in marketing margins. NGL margins are driven by $56 million in higher ethane and non-ethane per-unit prices, reflecting 19 percent higher realized non-ethane per-unit sales prices and 50 percent higher realized ethane per-unit sales prices. These increases were partially offset by $18 million in lower volumes primarily due to the sale of our Four Corners area assets in October 2018.
Other segment costs and expenses decreased primarily due to $57 million lower operating and maintenance and general and administrative costs. This reduction in costs is due primarily to the Four Corners area sale in October 2018, ongoing cost containment efforts, and the deconsolidation of our Jackalope interest in second quarter 2018. These reductions are partially offset by a $24 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.
Impairment of certain assets increased primarily due to the $1.849 billion impairment of certain assets in the Barnett Shale region in 2018, partially offset by the absence of a $1.019 billion impairment of certain gathering operations in the Mid-Continent region in 2017 (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements).
Gain on sale of certain assets reflects a gain from the sale of our Four Corners area assets in fourth quarter 2018.
Regulatory charges resulting from Tax Reform decreased primarily due to the absence of the $220 million initial regulatory charge associated with the impact of Tax Reform at Northwest Pipeline (see Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements).
Proportional Modified EBITDA of equity-method investments increased primarily due to the deconsolidation of our Jackalope interest, which is accounted for as an equity-method investment beginning in the second quarter of 2018.

2017 vs. 2016

West Modified EBITDA decreased primarily due to higher Impairment of certain assets, regulatory charges associated with the impact of Tax Reform at Northwest Pipeline, lower gathering rates, and lower volumes as a result of natural declines, partially offset by lower segment costs and expenses, higher per-unit NGL margins, and higher amortization of deferred revenue associated with the up-front cash payment received in conjunction with the fourth quarter 2016 Barnett Shale contract restructuring.

Service revenues decreased primarily due to:

- A $79 million decrease related to net lower gathering rates, primarily in the Barnett Shale area primarily due to the fourth quarter 2016 contract restructuring, as well as lower rates recognized in the Niobrara, Eagle Ford Shale, and Haynesville Shale regions. These rate decreases are offset by higher commodity-based fee revenues in the Piceance area primarily due to higher per-unit NGL margins and higher rates in the Wamsutter area as a result of renegotiated rates in conjunction with infrastructure expansions. Rates recognized in the Niobrara region represent a portion of the total contractual rate that is received, with the difference reflected as deferred revenue;
- A $34 million decrease driven by lower volumes in most gathering and processing regions primarily as a result of natural declines and more extreme weather conditions in the Rocky Mountains in the first quarter of 2017, partially offset by higher volumes in the Haynesville Shale region as a result of increased drilling in certain areas;
- A $39 million increase related to the rate of amortization of deferred revenue associated with the up-front cash payment received in conjunction with the fourth quarter 2016 Barnett Shale contract restructuring.

Product sales increased primarily due to:

- A $532 million increase in marketing revenues primarily due to a $450 million increase driven by higher prices and an $82 million increase driven by higher volumes. The average non-ethane per-unit sales price increased by 43 percent, the average ethane per-unit sales prices increased by 30 percent, and the average natural gas per-unit sales price increased by 13 percent. Ethane and non-ethane sales volumes were 28 percent and six percent higher, respectively, partially offset by 17 percent lower natural gas sales volumes. (Higher marketing sales revenues are substantially offset by higher Product costs);
- A $72 million increase in revenues associated with our equity NGLs primarily due to an $80 million increase driven by higher prices, partially offset by an $8 million decrease driven by lower volumes. Realized non-ethane prices increased by 42 percent and realized ethane prices increased by 46 percent. Non-ethane volumes decreased by six percent primarily due to natural declines and to severe winter conditions in the first quarter of 2017;
- A $24 million increase in other product sales related to certain fabricated equipment sales to affiliates (more than offset by higher other Product costs).

Product costs increased primarily due to:

- A $529 million increase in marketing purchases (more than offset in Product sales);
- A $30 million increase in natural gas purchases associated with the production of equity NGLs primarily due to a 26 percent increase in per-unit natural gas prices;
- A $25 million increase in other product costs related to certain fabricated equipment sales to affiliates (offset by higher other Product sales).

The decrease in Other segment costs and expenses reflects a $56 million decline in operating expenses, a $27 million reduction in general and administrative expenses, and $15 million of gains from contract settlements and terminations in Other (income) expense – net within Operating income (loss). The reductions in operating and general and administrative expenses are primarily due to the 2016 workforce reductions, ongoing cost containment efforts, lower compression expenses, favorable system gains and gas imbalance revaluations, and a reduced share of allocated support costs. These items are partially offset by a $13 million expense in 2017 related to a settlement charge from a pension early payout program (See Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements).
Impairment of certain assets increased primarily due to the $1.032 billion impairment of certain gathering operations primarily in the Mid-Continent region in 2017, partially offset by the absence of $100 million in impairments of certain Mid-Continent gathering assets and impairments or write-downs of other certain assets that may no longer be in use or are surplus in nature in 2016.
Regulatory charges resulting from Tax Reform reflects $220 million of regulatory charges associated with the impact of Tax Reform at Northwest Pipeline (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements).
Proportional Modified EBITDA of equity-method investments decreased primarily due to the divestiture of our interests of DBJV and Ranch Westex LLC late in the first quarter of 2017.

Other

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Other Modified EBITDA	$ (29)	$ 997	$ (696)

2018 vs. 2017

Modified EBITDA changed unfavorably primarily due to:

- The absence of a $1.095 billion gain on the sale of our Geismar Interest in 2017 (see Note 3 – Divestitures of Notes to Consolidated Financial Statements);
- The absence of $54 million of Modified EBITDA associated with the results of our former Geismar Olefins and RGP Splitter plants subsequent to their sale in July 2017;
- A $35 million charge in 2018 associated with a charitable contribution of preferred stock to The Williams Companies Foundation, Inc. (a not-for-profit corporation) (see Note 15 – 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 7 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- A $26 million decrease in income associated with a regulatory asset related to deferred taxes on equity funds used during construction;
- $20 million in costs in 2018 associated with the WPZ Merger (see Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements);
- The absence of a $12 million gain on the sale of the Refinery Grade Propylene Splitter in 2017 (see Note 7 – 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 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements);
- A decrease of $62 million for charges reducing regulatory assets related to deferred taxes on AFUDC resulting from Tax Reform (see Note 7 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- $40 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, Basis of Presentation, and Summary of Significant Accounting Policies 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;
- A $30 million favorable change in the settlement charge expense related to the program to pay out certain deferred vested pension benefits of employees associated with former operations (see Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements);
- A $20 million gain on the sale of certain assets and operations located in the Gulf Coast area (see Note 3 – Divestitures of Notes to Consolidated Financial Statements).

2017 vs. 2016

The favorable change in Modified EBITDA is primarily due to:

- A $1.095 billion gain recognized on the sale of our Geismar Interest in July 2017. (See Note 3 – Divestitures of Notes to Consolidated Financial Statements);
- The absence of the $747 million 2016 impairment of our Canadian operations, partially offset by the $23 million impairment of an olefins pipeline project in the Gulf Coast region in the second quarter of 2017 and the $68 million impairment of a certain NGL pipeline asset in the third quarter of 2017 (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements);
- The absence of $61 million of certain project development costs associated with the Canadian PDH facility that we expensed in 2016;
- A $65 million favorable change in the loss on the sale of our Canadian operations in September 2016;
- A $38 million decrease in costs related to our evaluation of strategic alternatives;
- The absence of $32 million of transportation and fractionation fees incurred in 2016 related to the Redwater fractionation facility, which was included in the sale of our Canadian operations in September 2016;
- A $29 million increase in income associated with an increase in a regulatory asset primarily driven by our increased ownership in WPZ.

These favorable changes are partially offset by:

- A $164 million decrease due to the absence of results from our former Geismar Olefins and RGP Splitter plants subsequent to their sale in July 2017;
- A $63 million charge reducing regulatory assets related to deferred taxes on AFUDC resulting from Tax Reform (see Note 7 – Other Income and Expenses of Notes to Consolidated Financial Statements);
- A $35 million settlement charge expense related to the program to pay out certain deferred vested pension benefits of employees associated with former operations. (See Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements);
- A reduction in revenues associated with an NGL pipeline near the Houston Ship Channel region;
- The absence of a $10 million gain on the sale of unused pipe in 2016.

Management’s Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2018, through the WPZ Merger, we streamlined our corporate structure and governance while improving our credit ratings to investment-grade. Additionally, we monetized assets, through sales of the Four Corners area assets and certain Gulf Coast pipeline systems which were not core to our business strategy, into a source for growth capital for acquisitions such as our RMM equity-method investment and a driver for improving credit metrics while continuing to reduce our direct commodity exposure.

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 2019 are currently expected to be in a range from $2.7 billion to $2.9 billion. Growth capital spending in 2019 includes Transco expansions, all of which are fully contracted with firm transportation agreements, and continuing to develop our gathering and processing infrastructure in the Northeast G&P and West segments. 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 our planned 2019 growth capital with retained cash flow and certain sources of available liquidity described below. 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 2019. Our potential material internal and external sources and uses of consolidated liquidity for 2019 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 December 31, 2018, we had a working capital deficit of $347 million, including cash and cash equivalents. Our available liquidity is as follows:

Available Liquidity	December 31, 2018
	(Millions)
Cash and cash equivalents	$ 168
Capacity available under our $4.5 billion credit facility, less amounts outstanding under our $4 billion commercial paper program (1)	4,340
	$ 4,508

(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. The highest amount outstanding under our current commercial paper program and credit facility during 2018 was $886 million. At December 31, 2018, we were in compliance with the financial covenants associated with our credit facility. See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on our credit facility and commercial paper program. Borrowing capacity available under our credit facility as of February 19, 2019, 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 each quarter of 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. There was no activity during 2018.

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. (See Note 6 – Investing Activities of Notes to Consolidated Financial Statements for our more significant equity-method investees.)

Credit Ratings

The interest rates at which we are able 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

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	Years Ended December 31, 2018	2017	2016
		(Millions)		
Sources of cash and cash equivalents:				
Operating activities – net	Operating	$3,293	$3,089	$4,155
Proceeds from long-term debt (see Note 14)	Financing	2,086	1,698	998
Proceeds from credit-facility borrowings	Financing	1,840	1,635	5,530
Proceeds from sale of businesses, net of cash divested (see Note 3)	Investing	1,296	2,067	1,020
Contributions in aid of construction	Investing	411	426	218
Proceeds from equity offerings	Financing	15	2,131	123
Proceeds from dispositions of equity-method investments (see Note 6)	Investing	—	200	34
Uses of cash and cash equivalents:				
Capital expenditures	Investing	(3,256)	(2,399)	(2,051)
Payments on credit-facility borrowings	Financing	(1,950)	(2,140)	(6,715)
Common dividends paid	Financing	(1,386)	(992)	(1,261)
Payments of long-term debt (see Note 14)	Financing	(1,254)	(3,785)	(375)
Purchases of and contributions to equity-method investments	Investing	(1,132)	(132)	(177)
Dividends and distributions paid to noncontrolling interests	Financing	(591)	(822)	(940)
Payments of commercial paper – net	Financing	(2)	(93)	(409)
Contribution to Gulfstream for repayment of debt (see Note 6)	Financing	—	—	(148)
Other sources / (uses) – net	Financing and Investing	(101)	(154)	68
Increase (decrease) in cash and cash equivalents		$(731)	$729	$70

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, Impairment of equity-method investments, Gain on sale of certain assets, Impairment of and net (gain) loss on sale of other assets and businesses, Gain on deconsolidation of businesses, and Regulatory charges resulting from Tax Reform.

Our Net cash provided (used) by operating activities in 2018 increased from 2017 primarily due to higher operating income (excluding noncash items as previously discussed) in 2018, partially offset by the impact of decreased distributions from unconsolidated affiliates in 2018.

Our Net cash provided (used) by operating activities in 2017 decreased from 2016 primarily due to the absence in 2017 of receipts from 2016 contract restructurings, partially offset by higher operating income and increased distributions from unconsolidated affiliates in 2017.

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

We have various other guarantees and commitments which are disclosed in Note 4 – Variable Interest Entities, Note 11 – Property, Plant, and Equipment, Note 14 – Debt, Banking Arrangements, and Leases, Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk, and Note 18 – Contingent Liabilities and Commitments 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.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2018:

	2019	2020 - 2021	2022 - 2023	Thereafter	Total
			(Millions)		
Long-term debt: (1)					
Principal	$47	$3,028	$ 3,654	$ 15,878	$22,607
Interest	1,170	2,147	1,868	9,410	14,595
Operating leases	34	59	39	86	218
Purchase obligations (2)	1,194	819	457	363	2,833
Other obligations (3)(4)	2	4	1	—	7
Total	$2,447	$6,057	$ 6,019	$ 25,737	$40,260

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(1) Includes the borrowings outstanding under credit facilities, but does not include any related variable-rate interest payments.

(2) Includes approximately $480 million in open property, plant, and equipment purchase orders. Includes an estimated $329 million long-term ethane purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2018 prices. This obligation is part of an overall exchange agreement whereby volumes we transport on OPPL are sold at a third-party fractionator near Conway, Kansas, and we are subsequently obligated to purchase ethane volumes at Mont Belvieu. The purchased ethane volumes may be utilized or sold at comparable prices in the Mont Belvieu market. Includes an estimated $453 million long-term ethane purchase obligation with index-based pricing terms that primarily supplies third parties at their plants and is reflected in this table at a value calculated using December 31, 2018 prices. Any excess purchased volumes may be sold at comparable market prices. Includes an estimated $211 million long-term mixed NGLs purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2018 prices. Includes an estimated $312 million long-term ethane purchase obligation with index-based pricing terms that primarily supplies a third party for consumption at their plant and is reflected in this table at a value calculated using December 31, 2018 prices. Any excess purchased volumes may be sold at comparable market prices. Includes an estimated $332 million long-term mixed NGLs purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2018 prices. In addition, we have not included certain natural gas life-of-lease contracts for which the future volumes are indeterminable. We have not included commitments, beyond purchase orders, for the acquisition or construction of property, plant, and equipment or expected contributions to our jointly owned investments. (See Company Outlook — Expansion Projects.)

(3) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $93 million in 2018 and $90 million in 2017. In 2019, we expect to contribute approximately $69 million to these plans (see Note 10 – Employee Benefit Plans of Notes to Consolidated Financial Statements). Tax-qualified pension plans are required to meet minimum contribution requirements. In the past, we have contributed amounts to our tax-qualified pension plans in excess of the minimum required contribution. These excess amounts can be used to offset future minimum contribution requirements. During 2018, we contributed $80 million to our tax-qualified pension plans. In addition to these contributions, a portion of the excess contributions was used to meet the minimum contribution requirements. During 2019, we expect to contribute approximately $60 million to our tax-qualified pension plans and use excess amounts to satisfy minimum contribution requirements, if

needed. Additionally, estimated future minimum funding requirements may vary significantly from historical requirements if actual results differ significantly from estimated results for assumptions such as returns on plan assets, interest rates, retirement rates, mortality, and other significant assumptions or by changes to current legislation and regulations.

(4) We have not included income tax liabilities in the table above. See Note 8 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of income taxes, including our contingent tax liability reserves.

Effects of Inflation

Our operations have historically not been materially affected by inflation. Approximately 50 percent of our gross property, plant, and equipment is comprised of our interstate natural gas pipeline assets. They are subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulations, along with competition and other market factors, may limit our ability to recover such increased costs. For our gathering and processing assets, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in crude oil and natural gas and related commodities than by changes in general inflation. Crude oil, natural gas, and NGL prices are particularly sensitive to the market perceptions concerning the supply and demand balance in the near future, as well as general economic conditions. However, our exposure to certain of these price changes is reduced through the fee-based nature of certain of our services and the use of hedging instruments.

Environmental

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 (see Note 18 – Contingent Liabilities and Commitments of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the 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. Current estimates of the most likely costs of such activities are approximately $35 million, all of which are included in Accrued liabilities and Regulatory liabilities, deferred income, and other in the Consolidated Balance Sheet at December 31, 2018. We will seek recovery of the accrued costs related to remediation activities by our interstate gas pipelines totaling approximately $6 million through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2018, we paid approximately $4 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $11 million in 2019 for these activities.

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 December 31, 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. The EPA previously issued its rule regarding National Ambient Air Quality Standards for ground-level ozone. We are monitoring the rule's implementation as it 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.

Our interstate natural gas pipelines consider prudently incurred environmental assessment and remediation costs and the costs associated with compliance with environmental standards to be recoverable through rates.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk
Interest Rate Risk
Our current interest rate risk exposure is related primarily to our debt portfolio. Our debt portfolio is primarily comprised of fixed rate debt, which mitigates the impact of fluctuations in interest rates. Any borrowings under our credit facility and any issuances under our commercial paper program could be at a variable interest rate and could expose us to the risk of increasing interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets. (See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements.)
The tables below provide information by maturity date about our interest rate risk-sensitive instruments as of December 31, 2018 and 2017. See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements for the methods used in determining the fair value of our long-term debt.

	2019	2020	2021	2022	2023	Thereafter (1)	Total	Fair Value December 31, 2018
	(Millions)							
Long-term debt, including current portion:								
Fixed rate	$47	$2,138	$890	$2,021	$1,473	$15,685	$22,254	$ 23,170
Weighted-average interest rate	5.2 %	5.2 %	5.2 %	5.3 %	5.5 %	5.7 %		
Variable rate (2)	$—	$—	$—	$—	$160	$—	$160	$ 160

	2018	2019	2020	2021	2022	Thereafter (1)	Total	Fair Value December 31, 2017
	(Millions)							
Long-term debt, including current portion:								
Fixed rate	$502	$33	$2,123	$873	$2,003	$15,131	$20,665	$ 22,735
Weighted-average interest rate	5.1 %	5.1 %	5.1 %	5.1 %	5.2 %	5.7 %		
Variable rate (3)	$—	$—	$—	$270	$—	$—	$270	$ 270

(1) Includes unamortized discount / premium and debt issuance costs.

(2) The weighted-average interest rate for our $160 million credit facility borrowing at December 31, 2018 was 3.77 percent.

(3) The weighted-average interest rate for our $270 million credit facility borrowing at December 31, 2017 was 3.16 percent.

Commodity Price Risk
We are exposed to the impact of fluctuations in the market price of NGLs and natural gas, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts, and limited proprietary trading activities. Our management of the risks associated with these market fluctuations includes maintaining sufficient liquidity, as well as using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. At December 31, 2018 and 2017, our derivative activity was not material. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm
The Stockholders and the Board of Directors of
The Williams Companies, Inc.

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the financial statement schedule listed in the index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, based on our audits and the reports of other auditors, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2018 and 2017, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.
We did not audit the financial statements of Gulfstream Natural Gas System, L.L.C. (Gulfstream), a limited liability corporation in which the Company has a 50 percent interest. In the consolidated financial statements, the Company's investment in Gulfstream was $225 million and $244 million as of December 31, 2018 and 2017, respectively, and the Company's equity earnings in the net income of Gulfstream were $75 million in 2018, $75 million in 2017 and $69 million in 2016. Gulfstream's financial statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulfstream, is based solely on the reports of the other auditors.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 21, 2019 expressed an unqualified opinion thereon.
Adoption of New Accounting Standards
As discussed in Note 1 and Note 2 to the consolidated financial statements, the Company changed its method for accounting for revenue in 2018.

Basis for Opinion
These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.
/s/ Ernst & Young LLP
We have served as the Company's auditor since 1962.
Tulsa, Oklahoma

February 21, 2019

Report of Independent Registered Public Accounting Firm

To the Management Committee and Members of Gulfstream Natural Gas System, L.L.C.:

Opinion on the Financial Statements

We have audited the balance sheets of Gulfstream Natural Gas System, L.L.C. (the "Company") as of December 31, 2018 and 2017, and the related statements of operations, comprehensive income, cash flows, and members' equity for the years then ended, including the related notes (collectively referred to as the "financial statements;" not presented herein). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2019

We have served as the Company's auditor since 2018.

Report of Independent Registered Public Accounting Firm

To the Members of Gulfstream Natural Gas System, L.L.C.

We have audited the statement of operations, comprehensive income, cash flows, and members’ equity of Gulfstream Natural Gas System, L.L.C. (the "Company") for the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the results of operations of Gulfstream Natural Gas System, L.L.C. and its cash flows for the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 22, 2017

The Williams Companies, Inc.
Consolidated Statement of Operations

	Years Ended December 31,		
	2018	2017	2016
	(Millions, except per-share amounts)		
Revenues:			
Service revenues	$5,502	$5,312	$5,171
Service revenues - commodity consideration (Note 1)	400	—	—
Product sales	2,784	2,719	2,328
Total revenues	8,686	8,031	7,499
Costs and expenses:			
Product costs	2,707	2,300	1,725
Processing commodity expenses (Note 1)	137	—	—
Operating and maintenance expenses	1,507	1,576	1,592
Depreciation and amortization expenses	1,725	1,736	1,763
Selling, general, and administrative expenses	569	594	722
Impairment of certain assets (Note 17)	1,915	1,248	873
Gain on sale of certain assets (Note 3)	(692)	(1,095)	—
Regulatory charges resulting from Tax Reform (Note 1)	(17)	674	—
Other (income) expense – net	67	71	135
Total costs and expenses	7,918	7,104	6,810
Operating income (loss)	768	927	689
Equity earnings (losses)	396	434	397
Impairment of equity-method investments (Note 17)	(32)	—	(430)
Other investing income (loss) – net	219	282	63
Interest incurred	(1,160)	(1,116)	(1,217)
Interest capitalized	48	33	38
Other income (expense) – net	92	(25)	85
Income (loss) before income taxes	331	535	(375)
Provision (benefit) for income taxes	138	(1,974)	(25)
Net income (loss)	193	2,509	(350)
Less: Net income (loss) attributable to noncontrolling interests	348	335	74
Net income (loss) attributable to The Williams Companies, Inc.	(155)	2,174	(424)
Preferred stock dividends (Note 15)	1	—	—
Net income (loss) available to common stockholders	$(156)	$2,174	$(424)
Basic earnings (loss) per common share:			
Net income (loss)	$(.16)	$2.63	$(.57)
Weighted-average shares (thousands)	973,626	826,177	750,673
Diluted earnings (loss) per common share:			
Net income (loss)	$(.16)	$2.62	$(.57)
Weighted-average shares (thousands)	973,626	828,518	750,673

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Net income (loss)	$193	$2,509	$(350)
Other comprehensive income (loss):			
Cash flow hedging activities:			
Net unrealized gain (loss) from derivative instruments, net of taxes of $1, $2, and ($1) in 2018, 2017, and 2016, respectively	(7)	(9)	4
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of ($1), ($1), and $1 in 2018, 2017, and 2016, respectively	8	6	(2)
Foreign currency translation activities:			
Foreign currency translation adjustments, net of taxes of ($37) in 2016	—	1	50
Reclassification into earnings upon sale of foreign entities, net of taxes of ($36) in 2016	—	—	119
Pension and other postretirement benefits:			
Amortization of prior service cost (credit) included in net periodic benefit cost (credit), net of taxes of $2 and $2 in 2017, and 2016, respectively	—	(3)	(4)
Net actuarial gain (loss) arising during the year, net of taxes of $3, ($15), and $8 in 2018, 2017 and 2016, respectively	(6)	44	(15)
Amortization of actuarial (gain) loss and net actuarial loss from settlements included in net periodic benefit cost (credit), net of taxes of ($11), ($37), and ($12) in 2018, 2017, and 2016, respectively (Note 10)	35	61	20
Other comprehensive income (loss)	30	100	172
Comprehensive income (loss)	223	2,609	(178)
Less: Comprehensive income (loss) attributable to noncontrolling interests	346	334	143
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$(123)	$2,275	$(321)

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet

	December 31, 2018	2017
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$168	$899
Trade accounts and other receivables (net of allowance of $9 at December 31, 2018 and $9 at December 31, 2017)	992	976
Inventories	130	113
Other current assets and deferred charges	174	191
Total current assets	1,464	2,179
Investments	7,821	6,552
Property, plant, and equipment – net	27,504	28,211
Intangible assets – net of accumulated amortization	7,767	8,791
Regulatory assets, deferred charges, and other	746	619
Total assets	$45,302	$46,352
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$662	$978
Accrued liabilities	1,102	1,167
Long-term debt due within one year	47	501
Total current liabilities	1,811	2,646
Long-term debt	22,367	20,434
Deferred income tax liabilities	1,524	3,147
Regulatory liabilities, deferred income, and other	3,603	3,950
Contingent liabilities and commitments (Note 18)		
Equity:		
Stockholders' equity:		
Preferred stock (Note 15)	35	—
Common stock ($1 par value; 1,470 million shares authorized at December 31, 2018 and 960 million shares authorized at December 31, 2017; 1,245 million shares issued at December 31, 2018 and 861 million shares issued at December 31, 2017)	1,245	861
Capital in excess of par value	24,693	18,508
Retained deficit	(10,002)	(8,434)
Accumulated other comprehensive income (loss)	(270)	(238)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	14,660	9,656
Noncontrolling interests in consolidated subsidiaries	1,337	6,519
Total equity	15,997	16,175
Total liabilities and equity	$45,302	$46,352

See accompanying notes.

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

	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, 2015	$—	$ 784	$ 14,807	$ (7,960)	$ (442)	$ (1,041)	$ 6,148	$ 10,077	$ 16,225
Net income (loss)	—	—	—	(424)	—	—	(424)	74	(350)
Other comprehensive income (loss)	—	—	—	—	103	—	103	69	172
Cash dividends – common stock ($1.68 per share)	—	—	—	(1,261)	—	—	(1,261)	—	(1,261)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(940)	(940)
Stock-based compensation and related common stock issuances, net of tax	—	1	56	—	—	—	57	—	57
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	—	114	114
Changes in ownership of consolidated subsidiaries, net	—	—	12	—	—	—	12	(18)	(6)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	29	29
Other	—	—	12	(4)	—	—	8	(2)	6
Net increase (decrease) in equity	—	1	80	(1,689)	103	—	(1,505)	(674)	(2,179)
Balance – December 31, 2016	—	785	14,887	(9,649)	(339)	(1,041)	4,643	9,403	14,046
Net income (loss)	—	—	—	2,174	—	—	2,174	335	2,509
Other comprehensive income (loss)	—	—	—	—	101	—	101	(1)	100
Issuance of common stock (Note 15)	—	75	2,043	—	—	—	2,118	—	2,118
Cash dividends – common stock ($1.20 per share)	—	—	—	(992)	—	—	(992)	—	(992)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(883)	(883)
Stock-based compensation and related common stock issuances, net of tax	—	1	73	—	—	—	74	—	74
Adoption of new accounting standard	—	—	1	36	—	—	37	—	37
	—	—	—	—	—	—	—	61	61

Sales of limited partner units of Williams Partners L.P.									
Changes in ownership of consolidated subsidiaries, net	—	—	1,497	—	—	—	1,497	(2,407)	(910)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	17	17
Other	—	—	7	(3)	—	—	4	(6)	(2)
Net increase (decrease) in equity	—	76	3,621	1,215	101	—	5,013	(2,884)	2,129
Balance – December 31, 2017	—	861	18,508	(8,434)	(238)	(1,041)	9,656	6,519	16,175
Adoption of new accounting standards (Note 1)	—	—	—	(23)	(61)	—	(84)	(37)	(121)
Net income (loss)	—	—	—	(155)	—	—	(155)	348	193
Other comprehensive income (loss)	—	—	—	—	32	—	32	(2)	30
WPZ Merger (Note 1)	—	382	6,112	—	(3)	—	6,491	(4,629)	1,862
Issuance of preferred stock (Note 15)	35	—	—	—	—	—	35	—	35
Cash dividends – common stock ($1.36 per share)	—	—	—	(1,386)	—	—	(1,386)	—	(1,386)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	—	(637)	(637)
Stock-based compensation and related common stock issuances, net of tax	—	1	60	—	—	—	61	—	61
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	—	—	—	—	—	—	—	15	15
Deconsolidation of subsidiary (Note 4)	—	—	—	—	—	—	—	(267)	(267)
Other	—	1	(1)	(4)	—	—	(4)	(1)	(5)
Net increase (decrease) in equity	35	384	6,185	(1,568)	(32)	—	5,004	(5,182)	(178)
Balance – December 31, 2018	$35	$ 1,245	$24,693	$(10,002)	$(270)	$(1,041)	$ 14,660	$ 1,337	$15,997

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

The Williams Companies, Inc.
Consolidated Statement of Cash Flows

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$193	$2,509	$(350)
Adjustments to reconcile to net cash provided (used) by operating activities:			
Depreciation and amortization	1,725	1,736	1,763
Provision (benefit) for deferred income taxes	220	(2,012)	(26)
Equity (earnings) losses	(396)	(434)	(397)
Distributions from unconsolidated affiliates	693	784	742
Net (gain) loss on disposition of equity-method investments	—	(269)	(27)
Impairment of equity-method investments (Note 17)	32	—	430
Gain on sale of certain assets (Note 3)	(692)	(1,095)	—
Impairment of and net (gain) loss on sale of other assets and businesses (Note 17)	1,915	1,249	918
Gain on deconsolidation of businesses (Note 6)	(203)	—	—
Amortization of stock-based awards	55	78	73
Regulatory charges resulting from Tax Reform (Note 1)	(15)	776	—
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(36)	(88)	82
Inventories	(16)	8	(25)
Other current assets and deferred charges	17	(21)	(4)
Accounts payable	(93)	118	35
Accrued liabilities	23	(92)	512
Other, including changes in noncurrent assets and liabilities	(129)	(158)	429
Net cash provided (used) by operating activities	3,293	3,089	4,155
FINANCING ACTIVITIES:			
Proceeds from (payments of) commercial paper – net	(2)	(93)	(409)
Proceeds from long-term debt	3,926	3,333	6,528
Payments of long-term debt	(3,204)	(5,925)	(7,091)
Proceeds from issuance of common stock	15	2,131	9
Proceeds from sale of limited partner units of consolidated partnership	—	—	114
Common dividends paid	(1,386)	(992)	(1,261)
Dividends and distributions paid to noncontrolling interests	(591)	(822)	(940)
Contributions from noncontrolling interests	15	17	29
Payments for debt issuance costs	(26)	(17)	(9)
Contribution to Gulfstream for repayment of debt	—	—	(148)
Other – net	(46)	(92)	(16)
Net cash provided (used) by financing activities	(1,299)	(2,460)	(3,194)
INVESTING ACTIVITIES:			
Property, plant, and equipment:			
Capital expenditures (1)	(3,256)	(2,399)	(2,051)
Dispositions – net	(7)	(41)	30
Contributions in aid of construction	411	426	218
Proceeds from sale of businesses, net of cash divested	1,296	2,067	1,020
Proceeds from dispositions of equity-method investments	—	200	34
Purchases of and contributions to equity-method investments	(1,132)	(132)	(177)
Other – net	(37)	(21)	35
Net cash provided (used) by investing activities	(2,725)	100	(891)

Increase (decrease) in cash and cash equivalents	(731)	729	70
Cash and cash equivalents at beginning of year	899	170	100
Cash and cash equivalents at end of year	$168	$899	$170

(1) Increases to property, plant, and equipment	$(3,021)	$(2,662)	$(1,912)
Changes in related accounts payable and accrued liabilities	(235)	263	(139)
Capital expenditures	$(3,256)	$(2,399)	$(2,051)

See accompanying notes.

The Williams Companies, Inc.
Notes to Consolidated Financial Statements

Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies
General
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), our previously consolidated master limited partnership, 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 noncash 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) (AOCI) 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 common units to the public in 2018, 2017, and 2016 associated with reinvested distributions of $46 million, $61 million, and $10 million, respectively.
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 (see Note 15 – Stockholders' Equity). 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 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.
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 (UEOM), a 69 percent equity-method investment in Laurel Mountain

Midstream, LLC (Laurel Mountain), a 58 percent equity-method investment in Caiman Energy II, LLC (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, 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. (Gulfstream), a 60 percent equity-method investment in Discovery Producer Services LLC (Discovery), and a 41 percent interest in Constitution Pipeline Company, LLC (Constitution) (a consolidated entity), which is developing a pipeline project (see Note 4 – Variable Interest Entities).

West is comprised of our interstate natural gas pipeline, Northwest Pipeline LLC (Northwest Pipeline), and our gathering, processing, and treating operations in Colorado, Wyoming, and 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 (OPPL), 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 50 percent equity-method investment in Rocky Mountain Midstream Holdings LLC (RMM), a 15 percent equity-method investment in Brazos Permian II, LLC (Brazos Permian II), and our previously owned 50 percent equity-method investment in the Delaware basin gas gathering system (DBJV) in the Mid-Continent region (see Note 6 – Investing Activities). West also included our former natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado (see Note 3 – Divestitures).

Other includes our previously owned operations, 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), which was sold in July 2017 (see Note 3 – Divestitures), and a refinery grade propylene splitter in the Gulf region, which was sold in June 2017. This segment also included our previously owned Canadian assets, which included an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility at Redwater, Alberta. In September 2016, these Canadian operations were sold. Other also includes minor business activities that are not operating segments, as well as corporate operations.

Basis of Presentation

Significant risks and uncertainties

We believe that the carrying value of certain of our property, plant, and equipment and other identifiable intangible assets, notably certain acquired assets accounted for as business combinations between 2012 and 2014, may be in excess of current fair value. However, the carrying value of these assets, in our judgment, continues to be recoverable based on our evaluation of undiscounted future cash flows. It is reasonably possible that future strategic decisions, including transactions such as monetizing non-core assets or contributing assets to new ventures with third parties, as well as unfavorable changes in expected producer activities could impact our assumptions and ultimately result in impairments of these assets. Such transactions or developments may also indicate that certain of our equity-method investments have experienced other-than-temporary declines in value, which could also result in impairment.

On March 15, 2018, the Federal Energy Regulatory Commission (FERC) issued a revised policy statement (the revised policy 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

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

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 revised policy 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. 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 that 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 (i) the reduction in the corporate income tax is already addressed in Northwest Pipeline’s 2017 rate settlement, and (ii) as discussed above, the WPZ Merger allows for the continued recovery of income tax allowances in Northwest Pipeline’s rates. The FERC agreed and granted Northwest Pipeline’s petition for waiver on November 19, 2018. On October 11, 2018 and December 6, 2018, Discovery Gas Transmission, LLC and Pine Needle LNG Company, LLC, respectively, filed their Form 501-Gs, including explanations as to why no adjustments to rates are needed.

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.

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of all entities that we control and our proportionate interest in the accounts of certain ventures in which we own an undivided interest. Our judgment is required to evaluate whether we control an entity. Key areas of that evaluation include:

- Determining whether an entity is a variable interest entity (VIE);
- Determining whether we are the primary beneficiary of a VIE, including evaluating which activities of the VIE most significantly impact its economic performance and the degree of power that we and our related parties have over those activities through our variable interests;

- Identifying events that require reconsideration of whether an entity is a VIE and continuously evaluating whether we are a VIE's primary beneficiary;
- Evaluating whether other owners in entities that are not VIEs are able to effectively participate in significant decisions that would be expected to be made in the ordinary course of business such that we do not have the power to control such entities.

We apply the equity method of accounting to investments over which we exercise significant influence but do not control.

Equity-method investment basis differences

Differences between the cost of our equity-method investments and our underlying equity in the net assets of investees are accounted for as if the investees were consolidated subsidiaries. Equity earnings (losses) in the Consolidated Statement of Operations includes our allocable share of net income (loss) of investees adjusted for any depreciation and amortization, as applicable, associated with basis differences.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us 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.

Significant estimates and assumptions include:

- Impairment assessments of investments, property, plant, and equipment, and other identifiable intangible assets;
- Litigation-related contingencies;
- Environmental remediation obligations;
- Depreciation and/or amortization of long-lived assets;
- Depreciation and/or amortization of equity-method investment basis differences;
- Asset retirement obligations (AROs);
- Pension and postretirement valuation variables;
- Measurement of regulatory liabilities;
- Measurement of deferred income tax assets and liabilities, including assumptions related to the realization of deferred income tax assets.

These estimates are discussed further throughout these notes.

Regulatory accounting

Transco and Northwest Pipeline are regulated by the FERC. Their rates, which are established by the FERC, are designed to recover the costs of providing the regulated services, and their competitive environment makes it probable that such rates can be charged and collected. Therefore, we have determined that it is appropriate under Accounting Standards Codification (ASC) Topic 980, "Regulated Operations," (ASC 980) to account for and report regulatory assets and liabilities related to these operations consistent with the economic effect of the way in which their rates are

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

established. Accounting for these operations that are regulated can differ from the accounting requirements for nonregulated operations. For example, for regulated operations, allowance for funds used during construction (AFUDC) represents the estimated cost of debt and equity funds applicable to utility plant in the process of construction and is capitalized as a cost of property, plant, and equipment because it constitutes an actual cost of construction under established regulatory practices; nonregulated operations are only allowed to capitalize the cost of debt funds related to construction activities, while a component for equity is prohibited. The components of our regulatory assets and liabilities relate to the effects of deferred taxes on equity funds used during construction, asset retirement obligations, fuel cost differentials, levelized incremental depreciation, negative salvage, pension and other postretirement benefits, and rate allowances for deferred income taxes at a historically higher federal income tax rate.
In December 2017, Tax Reform was enacted, which, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent (see Note 8 – Provision (Benefit) for Income Taxes). In accordance with ASC 980-740-25-2, Transco and Northwest Pipeline have recognized regulatory liabilities to reflect the probable return to customers through future rates of the future decrease in income taxes payable associated with Tax Reform. These liabilities represent an obligation to return amounts directly to our customers. While a majority of our customers have entered into tariff rates based on our cost-of-service proceedings and related rate base therein, certain other contracts with customers reflect contractually-based rates that are designed to recover the cost of providing those services, including an allowance for income taxes, with no expected future rate adjustment for the term of those contracts. This relative mix of contracts for services was considered in determining the probable amount to be returned to customers through future rates. The regulatory liabilities were recorded in December 2017 through regulatory charges to operating income totaling $674 million. As of December 31, 2018, the balance of these regulatory liabilities totaled $657 million. 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.
Certain of our equity-method investees recorded similar regulatory liabilities, for which our Equity earnings (losses) in the Consolidated Statement of Operations for 2017 were reduced by $11 million related to our proportionate share of the associated regulatory charges.
Our regulatory assets associated with the effects of deferred taxes on equity funds used during construction were also impacted by Tax Reform and were reduced by $102 million in December 2017 through a charge to Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Operations (see Note 7 – Other Income and Expenses). This amount, along with the previously described charges for establishing the regulatory liabilities resulting from Tax Reform, is reported within Regulatory charges resulting from Tax Reform within the Consolidated Statement of Cash Flows.
Our current and noncurrent regulatory asset and liability balances for the years ended December 31, 2018 and 2017 are as follows:

	December 31,	
	2018	2017
	(Millions)	
Current assets reported within Other current assets and deferred charges	$103	$102

Noncurrent assets reported within Regulatory assets, deferred charges, and other	495	376
Total regulated assets	$598	$478
Current liabilities reported within Accrued liabilities	$5	$18
Noncurrent liabilities reported within Regulatory liabilities, deferred income, and other	1,321	1,250
Total regulated liabilities	$1,326	$1,268

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

Cash and cash equivalents
Cash and cash equivalents consist of highly liquid investments with original maturities of three months or less when acquired.
Accounts receivable
Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. 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. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.
Inventories
Inventories in the Consolidated Balance Sheet primarily consist of NGLs, natural gas in underground storage, and materials and supplies and are stated at the lower of cost or net realizable value. The cost of inventories is primarily determined using the average-cost method.
Property, plant, and equipment
Property, plant, and equipment is initially recorded at cost. We base the carrying value of these assets on estimates, assumptions, and judgments relative to capitalized costs, useful lives, and salvage values.
As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at FERC-prescribed rates. Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except for certain offshore facilities that apply an accelerated depreciation method.
Gains or losses from the ordinary sale or retirement of property, plant, and equipment for regulated pipelines are credited or charged to accumulated depreciation. Other gains or losses are recorded in Other (income) expense – net included in Operating income (loss) in the Consolidated Statement of Operations.
Ordinary maintenance and repair costs are generally expensed as incurred. Costs of major renewals and replacements are capitalized as property, plant, and equipment.
We record a liability and increase the basis in the underlying asset for the present value of each expected future ARO at the time the liability is initially incurred, typically when the asset is acquired or constructed. As regulated entities, Northwest Pipeline and Transco offset the depreciation of the underlying asset that is attributable to capitalized ARO cost to a regulatory asset as we expect to recover these amounts in future rates. We measure changes in the liability due to passage of time by applying an interest rate to the liability balance. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in Operating and maintenance expenses in the Consolidated Statement of Operations, except for regulated entities, for which the liability is offset by a regulatory asset. The regulatory asset is amortized commensurate with our collection of those costs in rates.
Measurements of AROs include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market-risk premium.

Other intangible assets
Our identifiable intangible assets included within Intangible assets – net of accumulated amortization in the Consolidated Balance Sheet are primarily related to gas gathering, processing, and fractionation contractual customer

relationships. Our intangible assets are amortized on a straight-line basis over the period in which these assets contribute to our cash flows. We evaluate these assets for changes in the expected remaining useful lives and would reflect any changes prospectively through amortization over the revised remaining useful life.

Impairment of property, plant, and equipment, other identifiable intangible assets, and investments

We evaluate our property, plant, and equipment and other identifiable intangible assets for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred and we may apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

For assets identified to be disposed of in the future and considered held for sale, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment charge.

Judgments and assumptions are inherent in our estimate of undiscounted future cash flows and an asset’s or investment’s fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal.

Contingent liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable, and the amount of the loss can be reasonably estimated. These liabilities are calculated based upon our assumptions and estimates with respect to the likelihood or amount of loss and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matters. These calculations are made without consideration of any potential recovery from third parties. We recognize insurance recoveries or reimbursements from others when realizable. Revisions to these liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions or estimates.

Cash flows from revolving credit facilities and commercial paper program

Proceeds and payments related to borrowings under our credit facilities are reflected in the financing activities in the Consolidated Statement of Cash Flows on a gross basis. Proceeds and payments related to borrowings under our commercial paper program are reflected in the financing activities in the Consolidated Statement of Cash Flows on a net basis, as the outstanding notes generally have maturity dates less than three months from the date of issuance. (See Note 14 – Debt, Banking Arrangements, and Leases.)

Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as Treasury stock in the Consolidated Balance Sheet. Gains and losses on the subsequent reissuance of shares are credited or charged to Capital in excess of par value in the Consolidated Balance Sheet using the average-cost method.

Derivative instruments and hedging activities

We may utilize derivatives to manage a portion of our commodity price risk. These instruments consist primarily of swaps, futures, and forward contracts involving short- and long-term purchases and sales of energy commodities. We report the fair value of derivatives, except those for which the normal purchases and normal sales exception has been elected, in Other current assets and deferred charges; Regulatory assets, deferred charges, and other; Accrued liabilities; or Regulatory liabilities, deferred income, and other in the Consolidated Balance Sheet. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.)

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of physical energy commodities. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We may also designate a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in Product sales or Product costs in the Consolidated Statement of Operations.

For commodity derivatives designated as a cash flow hedge, the change in fair value of the derivative is reported in AOCI in the Consolidated Balance Sheet and reclassified into earnings in the period in which the hedged item affects earnings. Gains or losses deferred in AOCI associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in AOCI until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in AOCI is recognized in Product sales or Product costs in the Consolidated

Statement of Operations at that time. The change in likelihood of a forecasted transaction is a judgmental decision that includes qualitative assessments made by us.
For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in Product sales or Product costs in the Consolidated Statement of Operations.
Certain gains and losses on derivative instruments included in the Consolidated Statement of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded

on a net basis include unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives for NGL processing activities and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis.

Revenue recognition (subsequent to the adoption of ASC 606)

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, 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 Topic 606, "Revenue from Contracts with Customers" (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 regulated interstate natural gas pipeline businesses, which 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 fixed 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

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Notes to Consolidated Financial Statements – (Continued)

one-month periods or less. Our performance obligations related to our interstate natural gas pipeline businesses include the following:

- Firm 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;
- Interruptible transportation and storage under interruptible transportation and storage contracts—an integrated package of services typically constituting a single performance obligation once scheduled, which includes receiving, transporting or storing (as applicable), and redelivering commodities.

In situations where, in our judgment, 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 over time upon satisfaction of our daily stand ready 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 use judgment to 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 non-regulated gathering, processing, transportation, and storage midstream businesses 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, in our judgment, 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 judgmentally determined 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 as these methods appropriately match the consumption of services provided to the customer. The units of production methodology requires the use of production estimates that are uncertain and the use of judgment when developing estimates of future production volumes, thus impacting the rate of revenue recognition. Production estimates are monitored as circumstances and events warrant. 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, based on management's judgment, it 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.

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.

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Notes to Consolidated Financial Statements – (Continued)

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, in our judgment, 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.
Revenue recognition (prior to the adoption of ASC 606)
Revenues
As a result of the ratemaking process, certain revenues collected by us may be subject to refunds 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.
Service revenues
Revenues from our interstate natural gas pipeline businesses include services pursuant to long-term firm transportation and storage agreements. These agreements provide for a reservation charge based on the volume of contracted capacity and a commodity charge based on the volume of gas delivered, both at rates specified in our FERC tariffs. We recognize revenues for reservation charges ratably over the contract period 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 injection and withdrawal 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.
Certain revenues from our midstream operations include those derived from natural gas gathering, processing, treating, and compression services and are performed under volumetric-based fee contracts. These revenues are recorded when services have been performed.
Certain of our gas gathering and processing agreements have minimum volume commitments. If a customer under such an agreement fails to meet its minimum volume commitment for a specified period, generally measured on an annual basis, it is obligated to pay a contractually determined fee based upon the shortfall between actual production volumes and the minimum volume commitment for that period. The revenue associated with minimum volume

commitments is recognized in the period that the actual shortfall is determined and is no longer subject to future reduction or offset, which is generally at the end of the annual period or fourth quarter.

Crude oil gathering and transportation revenues and offshore production handling fees are recognized when the services have been performed. Certain offshore production handling contracts contain fixed payment terms that result in the deferral of revenues until such services have been performed or such capacity has been made available.

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Storage revenues from our midstream operations associated with prepaid contracted storage capacity contracts are recognized on a straight-line basis over the life of the contract as services are provided.

Product sales

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

We market NGLs, crude oil, and natural gas that we purchase from our producer customers as part of the overall service provided to producers. Revenues from marketing activities are recognized when the products have been sold and delivered.

Under our keep-whole and percent-of-liquids processing contracts, we retain the rights to all or a portion of the NGLs extracted from the producers' natural gas stream and recognize revenues when the extracted NGLs are sold and delivered.

Our former domestic olefins business produced olefins from purchased or produced feedstock and we recognized revenues when the olefins were sold and delivered.

Our Canadian businesses that were sold in September 2016 had processing and fractionation operations where we retained certain NGLs and olefins from an upgrader's offgas stream and we recognized revenues when the fractionated products were sold and delivered.

Interest capitalized

We capitalize interest during construction on major projects with construction periods of at least 3 months and a total project cost in excess of $1 million. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds (equity AFUDC). The latter is included in Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Operations. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by nonregulated companies are based on our average interest rate on debt.

Employee stock-based awards

We recognize compensation expense on employee stock-based awards on a straight-line basis; forfeitures are recognized when they occur. (See Note 16 – Equity-Based Compensation.)

Pension and other postretirement benefits

The funded status of each of the pension and other postretirement benefit plans is recognized separately in the Consolidated Balance Sheet as either an asset or liability. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. The plans' benefit obligations and net periodic benefit costs (credits) are actuarially determined and impacted by various assumptions and estimates. (See Note 10 – Employee Benefit Plans.)

The discount rates are determined separately for each of our pension and other postretirement benefit plans based on an approach specific to our plans. The year-end discount rates are determined considering a yield curve comprised of high-quality corporate bonds and the timing of the expected benefit cash flows of each plan.

The expected long-term rates of return on plan assets are determined by combining a review of the historical returns within the portfolio, the investment strategy included in the plans' investment policy statement, and capital market projections for the asset classes in which the portfolio is invested, as well as the weighting of each asset class.

Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in AOCI or, for Transco and Northwest Pipeline, as a regulatory asset or liability, until amortized as a component of net periodic benefit cost (credit). Unrecognized actuarial gains and losses in excess of 10 percent of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service, which is approximately 13 years for our pension plans and approximately 7 years for our other postretirement benefit plans.

The expected return on plan assets component of net periodic benefit cost (credit) is calculated using the market-related value of plan assets. For our pension plans, the market-related value of plan assets is equal to the fair value of plan assets adjusted to reflect the amortization of gains or losses associated with the difference between the expected and actual return on plan assets over a 5-year period. Additionally, the market-related value of assets may be no more than 110 percent or less than 90 percent of the fair value of plan assets at the beginning of the year. The market-related value of plan assets for our other postretirement benefit plans is equal to the unadjusted fair value of plan assets at the beginning of the year.

Income taxes

We include the operations of our domestic corporate subsidiaries and income from our subsidiary partnerships in our consolidated federal income tax return and also file tax returns in various foreign and state jurisdictions as required. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per common share

Basic earnings (loss) per common share in the Consolidated Statement of Operations is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. Diluted earnings (loss) per common share in the Consolidated Statement of Operations includes any dilutive effect of stock options, nonvested restricted stock units, and convertible debt, unless otherwise noted. Diluted earnings (loss) per common share are calculated using the treasury-stock method.

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 and prior to adopting this standard, the tax effects of items within accumulated other comprehensive income may not have reflected 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.

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 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.
In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09 establishing 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

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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.”

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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 are adopting ASU 2016-02 effective January 1, 2019.

We are substantially complete with our review of contracts to identify leases based on the modified definition of a lease and implementing 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. We are substantially complete with the implementation of ASU 2016-02 and 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, which we estimate to be less than 1 percent of total liabilities and total assets, respectively. We have also evaluated ASU 2016-02’s available practical expedients on adoption. We generally elected to adopt the practical expedients, which includes the practical expedient to not separate lease and non-lease components by both lessees and lessors by class of underlying assets and the land easements practical expedient.

Note 2 – Revenue Recognition

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)							
Year Ended December 31, 2018								
Revenues from contracts with customers:								
Service revenues:								
Non-regulated gathering, processing, transportation, and storage:								
Monetary consideration	$861	$ 541	$ 1,590	$—	$ —	$ 2	$ (73)	$2,921
Commodity consideration	20	59	321	—	—	—	—	400
Regulated interstate natural gas transportation and storage	—	—	—	1,921	443	—	(2)	2,362
Other	94	17	46	2	—	—	(15)	144

Total service revenues	975	617	1,957	1,923	443	2	(90)	5,827
Product Sales:								
NGL and natural gas	287	307	2,421	127	—	—	(382)	2,760
Other	—	—	21	—	—	—	(4)	17
Total product sales	287	307	2,442	127	—	—	(386)	2,777
Total revenues from contracts with customers	1,262	924	4,399	2,050	443	2	(476)	8,604
Other revenues (1)	21	18	12	11	—	32	(12)	82
Total revenues	$1,283	$ 942	$ 4,411	$2,061	$ 443	$ 34	$ (488)	$8,686

(1) Service revenues in our Consolidated Statement of Operations 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 Operations include amounts associated with our derivative contracts that are not within the scope of ASC 606.

Contract Assets

The following table presents a reconciliation of our contract assets:

	Year Ended December 31, 2018
	(Millions)
Balance at beginning of period	$ 4
Revenue recognized in excess of amounts invoiced	66
Minimum volume commitments invoiced	(66)
Balance at end of period	$ 4

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

Contract Liabilities

The following table presents a reconciliation of our contract liabilities:

	Year Ended December 31, 2018
	(Millions)
Balance at beginning of period	$ 1,596
Payments received and deferred	314
Noncash interest expense for significant financing component	16
Deconsolidation of Jackalope interest (Note 4)	(52)
Deconsolidation of certain Permian assets (Note 6)	(26)
Recognized in revenue	(451)
Balance at end of period	$ 1,397

The following table presents the amount of the contract liabilities balance as of December 31, 2018, expected to be recognized as revenue in each of the next five years as performance obligations are expected to be satisfied:

	(Millions)
2019	$ 271
2020	142
2021	121
2022	102
2023	95
Thereafter	666
Total	$ 1,397

Remaining Performance Obligations

The following table presents the transaction price allocated to the remaining performance obligations under certain contracts as of December 31, 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 December 31, 2018, that will be recognized in future periods (see above for Contract Liabilities and the expected recognition of those amounts within revenue). 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 December 31, 2018, do not consider potential future performance obligations for which the renewal has not been exercised.

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

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)
2019	$ 2,909
2020	2,728
2021	2,622
2022	2,262
2023	2,089
Thereafter	16,916
Total	$ 29,526

Accounts Receivable

The following is a summary of our Trade accounts and other receivables:

	December 31, 2018	January 1, 2018
	(Millions)	
Accounts receivable related to revenues from contracts with customers	$858	$ 958
Other accounts receivable	134	18
Total reflected in Trade accounts and other receivables	$992	$ 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, except per-share amounts)		
Consolidated Statement of Operations			
Year Ended December 31, 2018			
Service revenues	$5,502	$ 89	$ 5,591
Service revenues – commodity consideration	400	(400)	—
Product sales	2,784	135	2,919

Total revenues	8,686	(176)	8,510
Product costs	2,707	(124)	2,583
Processing commodity expenses	137	(137)	—
Operating and maintenance expenses	1,507	1	1,508
Depreciation and amortization expenses	1,725	2	1,727
Impairment of certain assets	1,915	202	2,117
Total costs and expenses	7,918	(56)	7,862
Operating income (loss)	768	(120)	648
Equity earnings (losses)	396	1	397
Other investing income (loss) – net	219	84	303
Interest incurred	(1,160)	16	(1,144)

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

	As Reported	Adjustments resulting from adoption of ASC 606	Balance without adoption of ASC 606
	(Millions, except per-share amounts)		
Interest capitalized	48	(10)	38
Income (loss) before income taxes	331	(29)	302
Provision (benefit) for income taxes	138	(9)	129
Net income (loss)	193	(20)	173
Less: Net income (loss) attributable to noncontrolling interests	348	(1)	347
Net income (loss) attributable to The Williams Companies, Inc.	(155)	(19)	(174)
Basic earnings (loss) per common share	$(0.16)	$ (0.02)	$ (0.18)
Diluted earnings (loss) per common share	(0.16)	(0.02)	(0.18)
Consolidated Statement of Comprehensive Income (Loss)			
Year Ended December 31, 2018			
Net income (loss)	$193	$ (20)	$ 173
Comprehensive income (loss)	223	(20)	203
Less: Comprehensive income (loss) attributable to noncontrolling interests	346	(1)	345
Comprehensive income (loss) attributable to The Williams Companies, Inc.	(123)	(19)	(142)
Consolidated Balance Sheet			
December 31, 2018			
Inventories	$130	$ (13)	$ 117
Total current assets	1,464	(13)	1,451
Investments	7,821	1	7,822
Property, plant, and equipment – net	27,504	(212)	27,292
Intangible assets – net of accumulated amortization	7,767	61	7,828
Regulatory assets, deferred charges, and other	746	(4)	742
Total assets	45,302	(167)	45,135
Accrued liabilities	1,102	67	1,169
Total current liabilities	1,811	67	1,878
Deferred income tax liabilities	1,524	20	1,544
Regulatory liabilities, deferred income, and other	3,603	(346)	3,257
Retained deficit	(10,002)	64	(9,938)

Total stockholders’ equity	14,660	64	14,724
Noncontrolling interests in consolidated subsidiaries	1,337	28	1,365
Total equity	15,997	92	16,089
Total liabilities and equity	45,302	(167)	45,135
Consolidated Statement of Changes in Equity			
December 31, 2018			
Adoption of ASC 606	$(121)	$ 121	$ —
Net income (loss)	193	(20)	173
Deconsolidation of subsidiary	(267)	(9)	(276)
Net increase (decrease) in equity	(178)	92	(86)
Balance at December 31, 2018	15,997	92	16,089

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

Note 3 – Divestitures
Sale of Gulf Coast Pipeline Systems
In November 2018, we completed the sale of certain assets and operations located in the Gulf Coast area for $177 million in cash. These assets were designated as held for sale during the third quarter of 2018. As a result of this sale, we recorded a gain of approximately $101 million in the fourth quarter of 2018, consisting of $81 million in our Atlantic-Gulf segment and $20 million in Other.

Previous impairments made to a portion of these assets and operations include $66 million related to certain idle pipelines in the second quarter of 2018, as well as $68 million and $23 million related to an NGL pipeline near the Houston Ship Channel region and project development costs associated with an olefins pipeline project, respectively, in 2017. These impairments are reflected in Impairment of certain assets in the Consolidated Statement of Operations. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) The results of operations for this disposal group, excluding the impairments and gains noted, were not significant for the reporting periods.
Sale of Four Corners Assets
In October 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. These assets were designated as held for sale during the third quarter of 2018. As a result of this sale, we recorded a gain of approximately $591 million within the West segment in the fourth quarter of 2018.
The following table presents the results of operations for the Four Corners area, excluding the gain noted above:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Income (loss) before income taxes of Four Corners area	$ 52	$ 47	$ 37
Income (loss) before income taxes of Four Corners area attributable to The Williams Companies, Inc.	43	35	23

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

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		

Income (loss) before income taxes of the Geismar Interest	$—	$ 26	$ 141
Income (loss) before income taxes of the Geismar Interest attributable to The Williams Companies, Inc.	—	19	85

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Sale of Canadian Operations

In September 2016, we completed the sale of subsidiaries conducting Canadian operations (such subsidiaries, the Canadian disposal group). Consideration received totaled $1.020 billion, net of $31 million of cash divested and subject to customary working capital adjustments.

During 2016, we designated these operations as held for sale. As a result, we measured the fair value of the disposal group, resulting in an impairment charge of $747 million, reflected in Impairment of certain assets in the Consolidated Statement of Operations. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) Upon completion of the sale, we also recorded a loss of $66 million in Other, primarily reflecting revisions to the sales price and estimated contingent consideration. This included a $15 million benefit related to transactions to hedge our foreign currency exchange risk on the Canadian proceeds, reflected in Other (income) expense – net within Costs and expenses in the Consolidated Statement of Operations.

For the year ended December 31, 2016, the results of operations for the Canadian disposal group, excluding the impairment and loss noted, were a loss before income taxes of $98 million, and a loss before income taxes attributable to The Williams Companies, Inc. of $95 million, in Other.

Note 4 – Variable Interest Entities

Consolidated VIEs

As of December 31, 2018, we consolidate the following 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.

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

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. On November 5, 2018, the FERC granted our request for an extension of time to December 2, 2020, to construct and place into service the Constitution pipeline. And, in September 2018, we filed a petition with the D.C. Circuit for review of the FERC's denial of our petition for declaratory order. An unfavorable resolution of that appeal could result in the impairment of a significant portion of the capitalized project costs, which total $377 million on a consolidated basis at December 31, 2018, and are included within Property, plant, and equipment – net 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 Williams Companies, Inc.
Notes to Consolidated Financial Statements – (Continued)

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

	December 31, 2018	2017 (1)	Classification
	(Millions)		
Assets (liabilities):			
Cash and cash equivalents	$33	$ 881	Cash and cash equivalents
Trade accounts and other receivables – net	62	972	Trade accounts and other receivables
Inventories	—	113	Inventories
Other current assets	2	176	Other current assets and deferred charges
Investments	—	6,552	Investments
Property, plant, and equipment – net	2,363	27,912	Property, plant, and equipment – net
Intangible assets – net	1,177	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	(15)	(957)	Accounts payable
Accrued liabilities including current asset retirement obligations	(115)	(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	(105)	(944)	Regulatory liabilities, deferred income, and other
Long-term deferred income	(159)	(1,119)	Regulatory liabilities, deferred income, and other
Regulatory liabilities and other	—	(1,690)	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, Basis of Presentation, and Summary of Significant Accounting Policies).

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, 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 6 – Investing Activities). At December 31, 2018, the carrying value of our investment in Jackalope was $343 million. Our maximum exposure to loss is limited to the carrying value of our investment. Jackalope is currently undertaking an expansion project with a remaining cost up to approximately $350 million as of December 31, 2018, which will be funded on a proportional basis.

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

Brazos Permian II
We own a 15 percent interest in Brazos Permian II (see Note 6 – Investing Activities), which provides gathering and processing services in the Delaware basin and is a VIE due primarily to our limited participating rights as the minority equity holder. At December 31, 2018, the carrying value of our investment in Brazos Permian II was $191 million. Our maximum exposure to loss is limited to the carrying value of our investment.

Note 5 – Related Party Transactions

Transactions with Equity-Method Investees

We have purchases from our equity-method investees included in Product costs in the Consolidated Statement of Operations of $236 million, $226 million, and $180 million for the years ended 2018, 2017, and 2016, respectively. We have $18 million and $20 million included in Accounts payable in the Consolidated Balance Sheet with our equity-method investees at December 31, 2018 and 2017, respectively.

We have operating agreements with certain equity-method investees. These operating agreements typically provide for reimbursement or payment to us for certain direct operational payroll and employee benefit costs, materials, supplies, and other charges and also for management services. The total charges to equity-method investees for these fees are $75 million, $67 million, and $66 million for the years ended 2018, 2017, and 2016, respectively.

Board of Directors

A former member of our Board of Directors, who was elected in 2013 and resigned during 2016, is also the current chairman, president, and chief executive officer of an energy services company that is a customer of ours. We recorded $144 million in Service revenues in the Consolidated Statement of Operations from this company for transportation and storage of natural gas for the year ended December 31, 2016.

Note 6 – Investing Activities

Brazos Permian II Equity-Method Investment

During the fourth quarter of 2018, we contributed the majority of our existing Delaware basin assets and $27 million in cash in exchange for a 15 percent interest in the Brazos Permian II, which consists of gas and crude oil gathering pipelines, natural gas processing, and oil storage facilities. We recorded a deconsolidation gain of $141 million reflected in Other investing income (loss) – net in the Consolidated Statement of Operations reflecting the excess of the fair value of our acquired interest over the carrying value of the assets contributed. We estimated the fair value of our interest to be $192 million primarily using a market approach (a Level 3 measurement within the fair value hierarchy). This approach involved the observation of recent transaction multiples in the Permian basin, including recent acquisitions consummated during 2018. Our interest in Brazos Permian II is considered an equity-method investment due to the fact that we are able to exert significant influence over its operating and financial policies.

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 has since increased to 50 percent at December 31, 2018, based on additional capital contributions made since the initial purchase.

Jackalope Deconsolidation

During the second quarter of 2018, we deconsolidated our interest in Jackalope (see Note 4 – 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 Operations. 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 sold all of our interest in Ranch Westex JV LLC (Ranch Westex) 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 Operations.

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.

Impairment of equity-method investments

The following table presents other-than-temporary impairment charges related to certain equity-method investments (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk):

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Northeast G&P			
UEOM	$32	$ —	$ —
Appalachia Midstream Investments	—	—	294
Laurel Mountain	—	—	50
West			
DBJV	—	—	59
Ranch Westex	—	—	24
Other	—	—	3
	$32	$ —	$430

Other investing income (loss) – net

In 2016, we recognized a $27 million gain from the sale of an equity-method investment interest in a gathering system that was part of the Appalachia Midstream Investments.

Other investing income (loss) – net also includes $36 million of interest income for 2016 associated with a receivable related to the sale of certain former Venezuela assets. Due to changes in circumstances that led to late payments and increased uncertainty regarding the recovery of the receivable, we began accounting for the receivable under a cost recovery model in first quarter 2015. Subsequently, we received payments greater than the remaining carrying amount of the receivable, which resulted in the recognition of interest income.

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

Investments

	Ownership Interest at December 31, 2018	December 31, 2018	2017
		(Millions)	
Equity-method investments:			
Appalachia Midstream Investments	(1)	$3,218	$3,104
UEOM	62%	1,293	1,383
RMM	50%	776	—
Discovery	60%	507	534
OPPL	50%	415	422
Caiman II	58%	412	429
Jackalope	50%	343	—
Laurel Mountain	69%	314	309
Gulfstream	50%	225	244
Brazos Permian II	15%	191	—
Other	Various	127	127
		$7,821	$6,552

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(1) Includes equity-method investments in multiple gathering systems in the Marcellus Shale with an approximate average 66 percent interest.

We have differences between the carrying value of our equity-method investments and the underlying equity in the net assets of the investees of $1.8 billion at December 31, 2018 and 2017. These differences primarily relate to our investments in Appalachia Midstream Investments and UEOM resulting from property, plant, and equipment, as well as customer-based intangible assets and goodwill.

Purchases of and contributions to equity-method investments

We generally fund our portion of significant expansion or development projects of these investees through additional capital contributions. These transactions increased the carrying value of our investments and included:

	Years Ended December 31, 2018	2017	2016
	(Millions)		
RMM	$ 795	$ —	$ —
Appalachia Midstream Investments	246	70	28
Jackalope	42	—	—
Brazos Permian II	27	—	—
Laurel Mountain	16	—	—
Discovery	5	1	—
DBJV	—	32	105

Caiman II	—	24	22
Other	1	5	22
	$ 1,132	$ 132	$ 177

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

Dividends and distributions
The organizational documents of entities in which we have an equity-method investment generally require distribution of available cash to members on at least a quarterly basis. These transactions reduced the carrying value of our investments and included:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Appalachia Midstream Investments	$ 297	$ 270	$ 211
Gulfstream	93	92	100
OPPL	73	68	69
UEOM	70	80	92
Caiman II	46	49	40
Discovery	45	127	141
DBJV	—	39	39
Laurel Mountain	23	32	28
Other	46	27	22
	$ 693	$ 784	$ 742

In addition, on September 24, 2015, we received a special distribution of $396 million from Gulfstream reflecting our proportional share of the proceeds from new debt issued by Gulfstream. The new debt was issued to refinance Gulfstream's debt maturities. Subsequently, we contributed $248 million and $148 million to Gulfstream for our proportional share of amounts necessary to fund debt maturities of $500 million due on November 1, 2015, and $300 million due on June 1, 2016, respectively.
Summarized Financial Position and Results of Operations of All Equity-Method Investments

	December 31,	
	2018	2017
	(Millions)	
Assets (liabilities):		
Current assets	$ 834	$ 447
Noncurrent assets	13,199	9,181
Current liabilities	(605)	(295)
Noncurrent liabilities	(2,491)	(1,538)

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		

Gross revenue	$2,411	$1,961	$1,883
Operating income	804	871	799
Net income	795	806	726

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

Note 7 – Other Income and Expenses

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

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Atlantic-Gulf			
Amortization of regulatory assets associated with asset retirement obligations	$ 33	$ 33	$ 33
Accrual of regulatory liability related to overcollection of certain employee expenses	22	22	25
Project development costs related to Constitution (Note 4)	4	16	28
Gains on asset retirements	(12)	—	(11)
West			
Gains on contract settlements and terminations	—	(15)	—
Regulatory charge per approved rates related to Tax Reform	24	—	—
Charge for regulatory liability associated with the decrease in Northwest Pipeline's estimated deferred state income tax rates following WPZ Merger	12	—	—
Other			
Gain on sale of Refinery Grade Propylene Splitter	—	(12)	—
Loss on sale of Canadian operations (Note 3)	—	5	66
Net foreign currency exchange (gains) losses (1)	—	—	10
Gain on sale of unused pipe	—	—	(10)
Benefit of regulatory asset associated with increase in Transco's estimated deferred state income tax rate following WPZ Merger	(37)	—	—

(1) Primarily relates to gains and losses incurred on foreign currency transactions and the remeasurement of U.S. dollar-denominated current assets and liabilities within our former Canadian operations (see Note 3 – Divestitures).

Additional Items

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

- Service revenues for the year ended December 31, 2016, includes $173 million associated with the amortization of deferred income related to the restructuring of certain gas gathering contracts in the Barnett Shale and Mid-Continent regions within the West segment.
- Service revenues for the year ended December 31, 2016 were reduced by $15 million related to potential refunds associated with a ruling received in certain rate case litigation within the Atlantic-Gulf segment.
- Selling, general, and administrative expenses for the year ended December 31, 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 15 – Stockholders' Equity). Selling, general, and administrative expenses for the year ended December 31, 2018, also includes $20 million for WPZ Merger related

costs within the Other segment.

- Selling, general, and administrative expenses and Operating and maintenance expenses for the year ended December 31, 2017, included $22 million in severance and other related costs within the Other segment. The year ended December 31, 2016, included $42 million in severance and other related costs associated with an

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

approximate 10 percent reduction in workforce in the first quarter of 2016, comprised of $3 million associated with the Northeast G&P segment, $8 million associated with the Atlantic-Gulf segment, $13 million associated with the West segment, and $18 million associated with the Other segment.

- Selling, general, and administrative expenses for the years ended December 31, 2017 and 2016 included $9 million and $47 million, respectively, of costs associated with our evaluation of strategic alternatives within the Other segment. Selling, general, and administrative expenses for the year ended December 31, 2016, also included $61 million of project development costs related to a proposed propane dehydrogenation facility in Alberta, Canada within the Other segment. Beginning in the first quarter of 2016, these costs did not qualify for capitalization.
- Other income (expense) – net below Operating income (loss) includes $89 million, $71 million, and $66 million for equity AFUDC primarily within the Atlantic-Gulf segment for the years ended December 31, 2018, 2017, and 2016, respectively. Other income (expense) – net below Operating income (loss) also includes $35 million, $52 million, and $23 million for the years ended December 31, 2018, 2017, and 2016, respectively, of income associated with regulatory assets related to the effects of deferred taxes on equity funds used during construction primarily within the Other segment.
- Other income (expense) – net below Operating income (loss) for the year ended December 31, 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. The year ended December 31, 2017, included 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 and 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 gain for the February 23, 2017, early retirement within the Other segment reflects $53 million of unamortized premium, partially offset by $23 million in premiums paid. The net loss for the July 3, 2017, early retirement within the Other segment reflects $51 million of unamortized premium, offset by $54 million in premiums paid (see Note 14 – Debt, Banking Arrangements, and Leases).
- Other income (expense) – net below Operating income (loss) includes settlement charge expense related to the program to pay out certain deferred vested pension benefits as follows (see Note 10 – Employee Benefit Plans):

	Years Ended December 31,	
	2018	2017
	(Millions)	
Atlantic-Gulf	$ 7	$ 15
Northeast	4	7
West	6	13
Other	5	35

- Other income (expense) – net below Operating income (loss) for the year ended December 31, 2017, included a $102 million charge for regulatory assets associated with the effects of deferred taxes on equity funds used during construction as a result of Tax Reform, comprised of $33 million within the Atlantic-Gulf segment, $6 million within the West segment, and $63 million within the Other segment (see Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies).

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Notes to Consolidated Financial Statements – (Continued)

Note 8 – Provision (Benefit) for Income Taxes

The Provision (benefit) for income taxes includes:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Current:			
Federal	$(83)	$15	$—
State	1	23	2
Foreign	—	—	(1)
	(82)	38	1
Deferred:			
Federal	183	(2,004)	(6)
State	37	(8)	61
Foreign	—	—	(81)
	220	(2,012)	(26)
Provision (benefit) for income taxes	$138	$(1,974)	$(25)

Reconciliations from the Provision (benefit) at statutory rate to recorded Provision (benefit) for income taxes are as follows:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Provision (benefit) at statutory rate	$69	$187	$(131)
Increases (decreases) in taxes resulting from:			
Impact of nontaxable noncontrolling interests	(73)	(117)	(22)
Federal Tax Reform rate change	—	(1,932)	—
State income taxes (net of federal benefit)	(10)	(17)	3
State deferred income tax rate change	38	26	43
Foreign operations – net (including tax effect of Canadian Sale)	—	(127)	78
Valuation allowance	105	—	—
Translation adjustment of certain unrecognized tax benefits	—	—	(1)
Other – net	9	6	5
Provision (benefit) for income taxes	$138	$(1,974)	$(25)

Income (loss) before income taxes includes $3 million, $7 million, and $885 million of foreign loss in 2018, 2017, and 2016, respectively.

Foreign operations – net (including tax effect of Canadian Sale) in 2016 reflects a valuation allowance associated with impairments and losses on the sale of our Canadian operations (see Note 3 – Divestitures) and the reversal of anticipatory foreign tax credits, partially offset by the tax effect of the impairments associated with our Canadian disposition. 2017 reflects the release of this valuation allowance.

On December 22, 2017, Tax Reform was enacted. Most of the provisions of Tax Reform were effective after January 1, 2018. However, the deferred tax impact of reducing the U.S. corporate tax rate from 35 percent to 21 percent was recognized in the period of enactment. This remeasurement resulted in a reduction of our deferred tax liabilities of approximately $1.9 billion, with a corresponding net adjustment to Provision (benefit) for income taxes in 2017.

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various

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

filing positions, we apply the two-step process of recognition and measurement. In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within Other – net in our reconciliation of the Provision (benefit) at statutory rate to recorded Provision (benefit) for income taxes.

Significant components of Deferred income tax liabilities and Deferred income tax assets are as follows. Following the WPZ Merger, the attributes below are presented based on the underlying assets.

	December 31,	
	2018	2017
	(Millions)	
Deferred income tax liabilities:		
Property, plant and equipment	$2,317	$—
Investments	295	3,565
Other	30	19
Total deferred income tax liabilities	2,642	3,584
Deferred income tax assets:		
Accrued liabilities	667	53
Minimum tax credit	71	155
Foreign tax credit	140	140
Federal loss carryovers	147	—
State losses and credits	319	283
Other	94	30
Total deferred income tax assets	1,438	661
Less valuation allowance	320	224
Net deferred income tax assets	1,118	437
Overall net deferred income tax liabilities	$1,524	$3,147

The valuation allowance at December 31, 2018 and 2017 serves to reduce the available deferred income tax assets to an amount that will, more likely than not, be realized. We consider all available positive and negative evidence, including projected future taxable income, which incorporates available tax planning strategies, and management's estimate of future reversals of existing taxable temporary differences, and have determined that a portion of our deferred income tax assets related to the Foreign tax credit and State losses and credits may not be realized. The Valuation allowance change from 2017 is primarily due to a $105 million valuation allowance associated with foreign tax credits, that expire between 2024 and 2028. The completion of the WPZ Merger (see Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies) was a taxable exchange to the WPZ unit holders, which resulted in an adjustment to the tax basis in the underlying assets deemed acquired. A reduction to the deferred tax liability of $1.829 billion related to the book-tax basis difference in this investment has been recorded. Increased tax depreciation from the additional tax basis will reduce future taxable income, which serves to impact our expected realization of the Foreign tax credit. The amounts presented in the table above are, with respect to state items, before any federal benefit. The change from prior year for the State losses and credits reflects increases in losses and credits generated in the current and prior years less losses and/or credits utilized in the current year. We have loss and credit carryovers in multiple state taxing jurisdictions. Additionally, valuation allowances on state net operating losses decreased by $31 million after the completion of the WPZ Merger. These attributes generally expire between 2019 and 2038 with some carryovers having indefinite carryforward periods. The remaining federal Minimum tax credit of $71 million will be refunded/utilized no later than 2021.

Federal loss carryovers includes deferred tax assets of $5 million at the end of 2018 that are expected to be utilized by us prior to expiration between 2019 and 2023. Deferred tax assets on net operating loss carryovers of $142 million have no expiration date.

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

Cash payments for income taxes (net of refunds) were $11 million, $28 million, and $5 million in 2018, 2017, and 2016, respectively.

As of December 31, 2018, we had approximately $51 million of unrecognized tax benefits. If recognized, income tax expense would be reduced by $51 million and $50 million for 2018 and 2017, respectively, including the effect of these changes on other tax attributes, with state income tax amounts included net of federal tax effect. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2018	2017
	(Millions)	
Balance at beginning of period	$ 50	$ 50
Additions for tax positions of prior years	1	—
Balance at end of period	$ 51	$ 50

We recognize related interest and penalties as a component of Provision (benefit) for income taxes. Total interest and penalties recognized as part of income tax provision were expenses of $800 thousand and $300 thousand for 2018 and 2016, respectively, and a benefit of $400 thousand for 2017. Approximately $3 million and $2 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2018 and 2017, respectively.

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.

Consolidated U.S. Federal income tax returns are open to Internal Revenue Service (IRS) examination for years after 2010. As of December 31, 2018, examinations of tax returns for 2011 through 2013 are currently in process. We do not expect material changes in our financial position resulting from these examinations. The statute of limitations for most states expires one year after expiration of the IRS statute. Generally, tax returns for our previously owned Canadian entities are open to audit for tax years after 2013. Tax years 2013 through 2016 are currently under examination. We have indemnified the purchaser for any adjustments to Canadian tax returns for periods prior to the sale of our Canadian operations in September 2016.

Note 9 – Earnings (Loss) Per Common Share

	Years Ended December 31,		
	2018	2017	2016
	(Dollars in millions, except per-share amounts; shares in thousands)		
Net income (loss) available to common stockholders	$ (156)	$ 2,174	$ (424)
Basic weighted-average shares	973,626	826,177	750,673
Effect of dilutive securities:			
Nonvested restricted stock units	—	1,704	—

Stock options	—	637	—
Diluted weighted-average shares (1)	973,626	828,518	750,673
Earnings (loss) per common share:			
Basic	$(.16)	$ 2.63	$ (.57)
Diluted	$(.16)	$ 2.62	$ (.57)

(1) For the years ended December 31, 2018 and December 31, 2016, 2.0 million and 0.6 million weighted-average nonvested restricted stock units, respectively, and 0.5 million and 0.5 million weighted-average stock options, respectively, have been excluded from the computation of diluted earnings (loss) per common share as their inclusion would be antidilutive due to our loss attributable to The Williams Companies, Inc.

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

Note 10 – Employee Benefit Plans

We have noncontributory defined benefit pension plans in which all eligible employees participate. Currently, eligible employees earn benefits primarily based on a cash balance formula. At the time of retirement, participants may elect, to the extent they are eligible for the various options, to receive annuity payments, a lump-sum payment, or a combination of annuity and lump-sum payments. In addition to our pension plans, we currently provide subsidized retiree medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized retiree medical benefits, except for participants that were employees or retirees of Transco Energy Company on December 31, 1995. Subsidized retiree medical benefits for eligible participants age 65 and older are paid through contributions to health reimbursement accounts. Subsidized retiree medical benefits for eligible participants under age 65 are provided through a self-insured medical plan sponsored by us. The self-insured retiree medical plan provides for retiree contributions and contains other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for this plan anticipates estimated future increases to our contribution levels to the health reimbursement accounts for participants age 65 and older, as well as future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases for participants under age 65.

In November 2018, we announced changes to our defined benefit pension plans and our defined contribution plan. Eligible employees hired or rehired on or after January 1, 2019, will not be eligible to participate in the pension plan, but will be eligible for an additional fixed annual contribution made by us to the defined contribution plan. Additionally, as of January 1, 2020, certain active eligible employees will no longer receive future compensation credits under the defined benefit pension plan, but will be eligible for an additional fixed annual contribution made by us to the defined contribution plan. Also as of January 1, 2020, certain active eligible employees will continue to receive compensation credits under the defined benefit pension plans and these employees will not be eligible to receive the fixed annual contribution under the defined contribution plan. As a result of this amendment, a curtailment gain and a prior service credit were recorded to Accumulated other comprehensive income (loss). The amounts of the curtailment gain and prior service credit were not significant and are reported in Net actuarial gain (loss) within the subsequent tables of changes in benefit obligations, amounts included in Accumulated other comprehensive income (loss), and other changes in plan assets and benefit obligations recognized in other comprehensive income (loss) before taxes.

In September 2017, we initiated a program to pay out certain deferred vested pension benefits to reduce investment risk, cash funding volatility, and administrative costs. In December 2017 and August 2018, lump-sum payments were made, and annuity payments commenced in relation to this program. As a result of these lump-sum payments, as well as lump-sum benefit payments made throughout 2017 and 2018, settlement accounting was required. We settled $103 million in liabilities of our pension plans in 2018 and $261 million in 2017 and recognized pre-tax, noncash settlement charges of $23 million in 2018 and $71 million in 2017, which are substantially reported in Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Operations (see Note 7 – Other Income and Expenses). These amounts are included within the subsequent tables of changes in benefit obligations and plan assets, net periodic benefit cost (credit), and other changes in plan assets and benefit obligations recognized in other comprehensive income (loss) before taxes.

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Notes to Consolidated Financial Statements – (Continued)

Funded Status

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,319	$1,466	$206	$197
Service cost	50	50	1	1
Interest cost	46	59	7	8
Plan participants’ contributions	—	—	2	3
Benefits paid	(35)	(35)	(13)	(14)
Net actuarial loss (gain)	(90)	40	(17)	11
Settlements	(103)	(261)	—	—
Net increase (decrease) in benefit obligation	(132)	(147)	(20)	9
Benefit obligation at end of year	1,187	1,319	186	206
Change in plan assets:				
Fair value of plan assets at beginning of year	1,227	1,254	227	208
Actual return on plan assets	(45)	184	(7)	25
Employer contributions	88	85	5	5
Plan participants’ contributions	—	—	2	3
Benefits paid	(35)	(35)	(13)	(14)
Settlements	(103)	(261)	—	—
Net increase (decrease) in fair value of plan assets	(95)	(27)	(13)	19
Fair value of plan assets at end of year	1,132	1,227	214	227
Funded status — overfunded (underfunded)	$(55)	$(92)	$28	$21
Accumulated benefit obligation	$1,171	$1,294		

The overfunded (underfunded) status of our pension plans and other postretirement benefit plan presented in the previous table are recognized in the Consolidated Balance Sheet within the following accounts:

	December 31,	
	2018	2017
	(Millions)	
Underfunded pension plans:		
Current liabilities	$ (2)	$ (2)
Noncurrent liabilities	(53)	(90)

Overfunded (underfunded) other postretirement benefit plan:		
Current liabilities	(6)	(6)
Noncurrent assets	34	27

The plan assets within our other postretirement benefit plan is intended to be used for the payment of benefits for certain groups of participants. The Current liabilities for the other postretirement benefit plan represent the current portion of benefits expected to be payable in the subsequent year for the groups of participants whose benefits are not expected to be paid from plan assets.

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

The pension plans’ benefit obligation Net actuarial loss (gain) of $(90) million in 2018 is primarily due to the impact of an increase in the discount rates utilized to calculate the benefit obligation. The pension plans’ benefit obligation Net actuarial loss (gain) of $40 million in 2017 is primarily due to the impact of a decrease in the discount rates utilized to calculate the benefit obligation.

The 2018 benefit obligation Net actuarial loss (gain) of $(17) million for our other postretirement benefit plan is primarily due to an increase in the discount rate used to calculate the benefit obligation. The 2017 benefit obligation Net actuarial loss (gain) of $11 million for our other postretirement benefit plan is primarily due to a decrease in the discount rate used to calculate the benefit obligation.

At December 31, 2018, one of our pension plans had plan assets in excess of its accumulated benefit obligation. For our other pension plans, the accumulated benefit obligation of $367 million exceeded plan assets of $326 million. All of our pension plans had a projected benefit obligation in excess of plan assets at December 31, 2018. At December 31, 2017, all of our pension plans had a projected benefit obligation and accumulated benefit obligation in excess of plan assets.

Pre-tax amounts not yet recognized in Net periodic benefit cost (credit) at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(Millions)			
Amounts included in Accumulated other comprehensive income (loss):				
Net actuarial loss	$(347)	$(375)	$(12)	$(21)
Amounts included in regulatory liabilities associated with Transco and Northwest Pipeline:				
Prior service credit	N/A	N/A	$—	$2
Net actuarial gain	N/A	N/A	4	14

In addition to the regulatory liabilities included in the previous table, differences in the amount of actuarially determined Net periodic benefit cost (credit) for our other postretirement benefit plan and the other postretirement benefit costs recovered in rates for Transco and Northwest Pipeline are deferred as a regulatory asset or liability. We have regulatory liabilities of $116 million at December 31, 2018 and $108 million at December 31, 2017, related to these deferrals. Additionally, Transco recognizes a regulatory liability for rate collections in excess of its amount funded to the tax-qualified pension plans. At December 31, 2018 and 2017, these regulatory liabilities were $49 million and $33 million, respectively. These pension and other postretirement plans amounts will be reflected in future rates based on the rate structures of these gas pipelines.

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Notes to Consolidated Financial Statements – (Continued)

Net Periodic Benefit Cost (Credit)

Net periodic benefit cost (credit) for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
	(Millions)					
Components of net periodic benefit cost (credit):						
Service cost	$50	$50	$54	$1	$1	$1
Interest cost	46	59	62	7	8	8
Expected return on plan assets	(63)	(82)	(85)	(11)	(11)	(12)
Amortization of prior service credit	—	—	—	(2)	(13)	(15)
Amortization of net actuarial loss	23	27	30	—	—	—
Net actuarial loss from settlements	23	71	2	—	—	—
Reclassification to regulatory liability	—	—	—	2	3	4
Net periodic benefit cost (credit)	$79	$125	$63	$(3)	$(12)	$(14)

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 Operations.

Items Recognized in Other Comprehensive Income (Loss) and Regulatory Assets and Liabilities

Other changes in plan assets and benefit obligations recognized in Other comprehensive income (loss) before taxes for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
	(Millions)					
Other changes in plan assets and benefit obligations recognized in Other comprehensive income (loss):						
Net actuarial gain (loss)	$(18)	$62	$(23)	$9	$(3)	$—
Amortization of prior service credit	—	—	—	—	(5)	(6)
Amortization of net actuarial loss	23	27	30	—	—	—
Net actuarial loss from settlements	23	71	2	—	—	—
Other changes in plan assets and benefit obligations recognized in Other comprehensive income (loss)	$28	$160	$9	$9	$(8)	$(6)

Other changes in plan assets and benefit obligations for our other postretirement benefit plan associated with Transco and Northwest Pipeline are recognized in regulatory assets and liabilities. Amounts recognized in regulatory assets and liabilities for the years ended December 31 consist of the following:

	2018	2017	2016
	(Millions)		
Other changes in plan assets and benefit obligations recognized in regulatory (assets) and liabilities:			
Net actuarial gain (loss)	$(10)	$ 6	$ 2
Amortization of prior service credit	(2)	(8)	(9)

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Notes to Consolidated Financial Statements – (Continued)

Key Assumptions
The weighted-average assumptions utilized to determine benefit obligations as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
Discount rate	4.34 %	3.66 %	4.39 %	3.71 %
Rate of compensation increase	4.83	4.93	N/A	N/A
Cash balance interest crediting rate	4.25	4.25	N/A	N/A

The weighted-average assumptions utilized to determine Net periodic benefit cost (credit) for the years ended December 31 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
Discount rate	3.67 %	4.17 %	4.37 %	3.71 %	4.27 %	4.50 %
Expected long-term rate of return on plan assets	5.34	6.45	6.85	4.95	5.53	6.11
Rate of compensation increase	4.93	4.87	4.88	N/A	N/A	N/A
Cash balance interest crediting rate	4.25	4.25	4.25	N/A	N/A	N/A

The mortality assumptions used to determine the benefit obligations for our pension and other postretirement benefit plans reflect generational projection mortality tables.
The assumed health care cost trend rate for 2019 is 7.5 percent. This rate decreases to 4.5 percent by 2026.
Plan Assets
Plan assets for our pension and other postretirement benefit plans consist primarily of equity and fixed income securities including mutual funds and commingled investment funds invested in equity and fixed income securities. The plans' investment policy provides for a strategy in accordance with the Employee Retirement Income Security Act (ERISA), which governs the investment of the assets in a diversified portfolio. The plans follow a policy of diversifying the investments across various asset classes and investment managers. Additionally, the investment returns on approximately 38 percent of the other postretirement benefit plan assets are subject to income tax; therefore, certain investments are managed in a tax efficient manner.
The investment policy for the pension plans includes a general target asset allocation at December 31, 2018, of 25 percent equity securities and 75 percent fixed income securities. The target allocation includes the investments in equity and fixed income mutual funds and commingled investment funds. The investment policy allows for a broad range of asset allocations that permit the plans to de-risk in response to changes in the plans' funded status.
Equity securities may include U.S. equities and non-U.S. equities. Investment in Williams' securities or an entity in which Williams has a majority ownership is prohibited except where these securities may be owned in a commingled investment fund in which the plans' trusts invest. No more than 5 percent of the total stock portfolio valued at market

may be invested in the common stock of any one corporation.

Fixed income securities may consist of U.S. as well as international instruments, including emerging markets. The fixed income strategies may invest in government, corporate, asset-backed securities, and mortgage-backed obligations. The weighted-average credit rating of the fixed income strategies must be at least “investment grade” including ratings by Moody’s and/or Standard & Poor’s. No more than 5 percent of the total fixed income portfolio may be invested in

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Notes to Consolidated Financial Statements – (Continued)

the fixed income securities of any one issuer with the exception of bond index funds and U.S. government guaranteed and agency securities.

The following securities and transactions are not authorized: unregistered securities, commodities or commodity contracts, short sales or margin transactions, or other leveraging strategies. Investment strategies using direct investments in derivative securities require approval and, historically, have not been used; however, these instruments may be used in mutual funds and commingled investment funds held by the plans' trusts. Additionally, real estate equity, natural resource property, venture capital, leveraged buyouts, and other high-return, high-risk investments are generally restricted.

There are no significant concentrations of risk within the plans' investment securities because of the diversity of the types of investments, diversity of the various industries, and the diversity of the fund managers and investment strategies. Generally, the investments held in the plans are publicly traded, therefore, minimizing liquidity risk in the portfolio.

The fair values of our pension plan assets at December 31, 2018 and 2017 by asset class are as follows:

	2018 Quoted Prices in Active Markets for Identical Assets (Level 1) (Millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Pension assets:				
Cash management fund	$ 10	$ —	$ —	$ 10
Equity securities:				
U.S. large cap	30	—	—	30
U.S. small cap	22	—	—	22
Fixed income securities (1):				
U.S. Treasury securities	157	—	—	157
Government and municipal bonds	—	21	—	21
Mortgage and asset-backed	—	48	—	48

securities				
Corporate bonds	—	210	—	210
Insurance company investment contracts and other	—	6	—	6
	$ 219	$ 285	$ —	504
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				123
Equities — International small cap				8
Equities — International emerging markets				19
Equities — International developed markets				51
Fixed income — U.S. long duration				335
Fixed income — Corporate bonds				92
Total assets at fair value at December 31, 2018				$ 1,132

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	2017 Quoted Prices in Active Markets for Identical Assets (Level 1) (Millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Pension assets:				
Cash management fund	$ 17	$ —	$ —	$ 17
Equity securities:				
U.S. large cap	62	—	—	62
U.S. small cap	54	—	—	54
Fixed income securities (1):				
U.S. Treasury securities	103	—	—	103
Government and municipal bonds	—	15	—	15
Mortgage and asset-backed securities	—	47	—	47
Corporate bonds	—	158	—	158
Insurance company investment contracts and other	—	5	—	5
	$ 236	$ 225	$ —	461
Commingled investment funds measured at net asset value practical				

expedient (2):	
Equities — U.S. large cap	265
Equities — International small cap	26
Equities — International emerging markets	41
Equities — International developed markets	110
Fixed income — U.S. long duration	205
Fixed income — Corporate bonds	119
Total assets at fair value at December 31, 2017	$ 1,227

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Notes to Consolidated Financial Statements – (Continued)

The fair values of our other postretirement benefits plan assets at December 31, 2018 and 2017 by asset class are as follows:

	2018 Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Other postretirement benefit assets:				
Cash management funds	$11	$ —	$ —	$11
Equity securities:				
U.S. large cap	20	—	—	20
U.S. small cap	9	—	—	9
International developed markets large cap growth	—	5	—	5
Fixed income securities (1):				
U.S. Treasury securities	19	—	—	19
Government and municipal bonds	—	2	—	2
Mortgage and asset-backed securities	—	6	—	6
Corporate bonds	—	25	—	25
Mutual fund — Municipal bonds	43	—	—	43
	$102	$ 38	$ —	140
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				14
Equities — International small cap				1
Equities — International emerging markets				2
Equities — International developed markets				6
Fixed income — U.S. long duration				40
Fixed income — Corporate bonds				11
Total assets at fair value at December 31, 2018				$214

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Notes to Consolidated Financial Statements – (Continued)

	2017 Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Other postretirement benefit assets:				
Cash management funds	$11	$ —	$ —	$11
Equity securities:				
U.S. large cap	25	—	—	25
U.S. small cap	14	—	—	14
International developed markets large cap growth	—	6	—	6
Fixed income securities (1):				
U.S. Treasury securities	12	—	—	12
Government and municipal bonds	—	2	—	2
Mortgage and asset-backed securities	—	5	—	5
Corporate bonds	—	19	—	19
Mutual fund — Municipal bonds	43	—	—	43
	$105	$ 32	$ —	137
Commingled investment funds measured at net asset value practical expedient (2):				
Equities — U.S. large cap				31
Equities — International small cap				3
Equities — International emerging markets				5
Equities — International developed markets				13
Fixed income — U.S. long duration				24
Fixed income — Corporate bonds				14
Total assets at fair value at December 31, 2017				$227

(1) The weighted-average credit quality rating of the fixed income security portfolio is investment grade with a weighted-average duration of approximately 13 years for 2018 and 12 years for 2017.

(2) The stated intents of the funds vary based on each commingled fund’s investment objective. These objectives generally include strategies to replicate or outperform various market indices. Certain standard withdrawal restrictions generally apply, which may include redemption notification period restrictions ranging from 10 days to 30 days. Additionally, the fund managers retain the right to restrict withdrawals from and/or purchases into the funds so as not to disadvantage other investors in the funds. Generally, the funds also reserve the right to make all or a portion of the redemption in-kind rather than in cash or a combination of cash and in-kind.

The fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement of an asset.

Shares of the cash management funds and mutual funds are valued at fair value based on published market prices as of the close of business on the last business day of the year, which represents the net asset values of the shares held.

The fair values of equity securities traded on U.S. exchanges are derived from quoted market prices as of the close of business on the last business day of the year. The fair values of equity securities traded on foreign exchanges are also derived from quoted market prices as of the close of business on an active foreign exchange on the last business day of the year. However, the valuation requires translation of the foreign currency to U.S. dollars and this translation is considered an observable input to the valuation.

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

The fair values of all commingled investment funds are determined based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate values of the funds' assets at fair value less liabilities, divided by the number of units outstanding.

The fair values of fixed income securities, except U.S. Treasury securities, are determined using pricing models. These pricing models incorporate observable inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads for similar securities to determine fair value. The U.S. Treasury securities are valued at fair value based on closing prices on the last business day of the year reported in the active market in which the security is traded.

There have been no significant changes in the preceding valuation methodologies used at December 31, 2018 and 2017. Additionally, there were no transfers or reclassifications of investments between Level 1 and Level 2 from December 2017 to December 2018. If transfers between levels had occurred, the transfers would have been recognized as of the end of the period.

Plan Benefit Payments and Employer Contributions

Following are the expected benefits to be paid by the plans. These estimates are based on the same assumptions previously discussed and reflect future service as appropriate. The actuarial assumptions are based on long-term expectations and include, but are not limited to, assumptions as to average expected retirement age and form of benefit payment. Actual benefit payments could differ significantly from expected benefit payments if near-term participant behaviors differ significantly from the actuarial assumptions.

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
2019	$ 85	$ 14
2020	87	14
2021	90	13
2022	90	14
2023	89	14
2024-2028	467	59

In 2019, we expect to contribute approximately $60 million to our tax-qualified pension plans and approximately $3 million to our nonqualified pension plans, for a total of approximately $63 million, and approximately $6 million to our other postretirement benefit plans.

Defined Contribution Plan

We also maintain a defined contribution plan for the benefit of substantially all of our employees. Generally, plan participants may contribute a portion of their compensation on a pre-tax and after-tax basis in accordance with the plan's guidelines. We match employees' contributions up to certain limits. Our matching contributions charged to expense were $35 million in 2018, $34 million in 2017, and $36 million in 2016.

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

Note 11 – Property, Plant, and Equipment

The following table presents nonregulated and regulated Property, plant, and equipment – net as presented on the Consolidated Balance Sheet for the years ended:

	Estimated Useful Life (1) (Years)	Depreciation Rates (1) (%)	December 31, 2018	December 31, 2017
			(Millions)	
Nonregulated:				
Natural gas gathering and processing facilities	5 - 40		$15,324	$18,440
Construction in progress	Not applicable		778	566
Other	2 - 45		2,356	2,776
Regulated:				
Natural gas transmission facilities		1.20 - 6.97	17,312	14,460
Construction in progress	Not applicable	Not applicable	965	1,637
Other	5 - 45	1.35 - 33.33	1,926	1,634
Total property, plant, and equipment, at cost			38,661	39,513
Accumulated depreciation and amortization			(11,157)	(11,302)
Property, plant, and equipment — net			$27,504	$28,211

(1) Estimated useful life and depreciation rates are presented as of December 31, 2018. Depreciation rates and estimated useful lives for regulated assets are prescribed by the FERC.

Depreciation and amortization expense for Property, plant, and equipment – net was $1.392 billion, $1.389 billion, and $1.407 billion in 2018, 2017, and 2016, respectively.

Regulated Property, plant, and equipment – net includes approximately $586 million and $626 million at December 31, 2018 and 2017, respectively, related to amounts in excess of the original cost of the regulated facilities within our gas pipeline businesses as a result of our prior acquisitions. This amount is being amortized over 40 years using the straight-line amortization method. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

Asset Retirement Obligations

Our accrued obligations relate to underground storage caverns, offshore platforms and pipelines, fractionation and compression facilities, gas gathering well connections and pipelines, and gas transmission pipelines and facilities. At the end of the useful life of each respective asset, we are legally obligated to plug storage caverns and remove any related surface equipment, to restore land and remove surface equipment at gas processing, fractionation, and compression facilities, to dismantle offshore platforms and appropriately abandon offshore pipelines, to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment, and to remove certain components of gas transmission facilities from the ground.

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

The following table presents the significant changes to our ARO, of which $968 million and $946 million are included in Regulatory liabilities, deferred income, and other with the remaining current portion in Accrued liabilities at December 31, 2018 and 2017, respectively.

	December 31,	
	2018	2017
	(Millions)	
Beginning balance	$998	$862
Liabilities incurred	21	33
Liabilities settled	(19)	(16)
Accretion expense (1)	71	141
Revisions (2)	(39)	(22)
Ending balance	$1,032	$998

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(1) The decrease in accretion expense in 2018 primarily reflects the absence of a 2017 adjustment associated with obligations identified from certain Transco land agreements.

(2) Several factors are considered in the annual review process, including inflation rates, current estimates for removal cost, market risk premiums, discount rates, and the estimated remaining useful life of the assets. The 2018 revisions reflect changes in removal cost estimates, decreases in the estimated remaining useful life of certain assets and increases in the discount rates used in the annual review process. The 2017 revisions reflect changes in removal cost estimates and decreases in the estimated remaining useful life of certain assets and discount rates used in the annual review process.

The funds Transco collects through a portion of its rates to fund its ARO are deposited into an external trust account dedicated to funding its ARO (ARO Trust). (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) Under its current rate settlement, Transco's annual funding obligation is approximately $36 million, with installments to be deposited monthly.

Note 12 – Other Intangible Assets

The gross carrying amount and accumulated amortization of other intangible assets, included in Intangible assets – net of accumulated amortization, at December 31 are as follows:

	2018		2017	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(Millions)			
Contractual customer relationships	$9,232	$ (1,465)	$10,027	$ (1,283)

Other intangible assets primarily relate to gas gathering, processing, and fractionation contractual customer relationships recognized in acquisitions. The decrease in the gross carrying amount of other intangible assets during 2018 is primarily related to the impairment of certain assets located in the Barnett Shale and the deconsolidation of our interest in Jackalope (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk and Note 6 – Investing Activities, respectively). These decreases are the primary reasons for the difference between the change in accumulated amortization during 2018 indicated above and the amortization expense for 2018 noted below. Other intangible assets are being amortized on a straight-line basis over an initial period of 30 years which represents a portion of the term over which the contractual customer relationships are expected to contribute to our cash flows. We expense costs incurred to renew or extend the terms of our gas gathering, processing, and fractionation contracts with customers based on the estimated future revenues during the contract periods (the weighted-average periods prior to the next renewal or extension of the associated contractual customer relationships as estimated at the time of the acquisition). Although a significant portion of the expected future cash flows associated with these contractual customer relationships are dependent on our ability to renew or extend the arrangements beyond the initial contract periods, these expected future cash flows are significantly influenced by the scope and pace of our producer customers' drilling programs. Once producer customers' wells are connected to our gathering infrastructure, their likelihood of switching to another provider before the wells are abandoned is reduced due to the significant capital investment required.

The amortization expense related to other intangible assets was $333 million, $347 million, and $356 million in 2018, 2017, and 2016, respectively. The estimated amortization expense for each of the next five succeeding fiscal years is approximately $312 million.

Note 13 – Accrued Liabilities

	December 31,	
	2018	2017
	(Millions)	
Interest on debt	$282	$267
Revenue contract liabilities (Note 2)	244	361
Employee costs	205	202
Other, including other loss contingencies	371	337
	$1,102	$1,167

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

Note 14 – Debt, Banking Arrangements, and Leases
Long-Term Debt

	December 31,	
	2018	2017
	(Millions)	
Transco:		
6.05% Notes due 2018	$—	$250
7.08% Debentures due 2026	8	8
7.25% Debentures due 2026	200	200
7.85% Notes due 2026	1,000	1,000
4% Notes due 2028	400	—
5.4% Notes due 2041	375	375
4.45% Notes due 2042	400	400
4.6% Notes due 2048	600	—
Other financing obligations	1,067	231
Northwest Pipeline:		
6.05% Notes due 2018	—	250
7.125% Debentures due 2025	85	85
4% Notes due 2027	500	250
WMB:		
4.125% Notes due 2020	600	600
5.25% Notes due 2020	1,500	1,500
4% Notes due 2021	500	500
7.875% Notes due 2021	371	371
3.35% Notes due 2022	750	750
3.6% Notes due 2022	1,250	1,250
3.7% Notes due 2023	850	850
4.5% Notes due 2023	600	600
4.3% Notes due 2024	1,000	1,000
4.55% Notes due 2024	1,250	1,250
4.875% Notes due 2024	—	750
3.9% Notes due 2025	750	750
4% Notes due 2025	750	750
3.75% Notes due 2027	1,450	1,450
7.5% Debentures due 2031	339	339
7.75% Notes due 2031	252	252
8.75% Notes due 2032	445	445

6.3% Notes due 2040	1,250	1,250
5.8% Notes due 2043	400	400
5.4% Notes due 2044	500	500
5.75% Notes due 2044	650	650
4.9% Notes due 2045	500	500
5.1% Notes due 2045	1,000	1,000
4.85% Notes due 2048	800	—
Various — 7.625% to 10.25% Notes and Debentures due 2019 to 2027	55	55
Credit facility loans	160	270
Debt issuance costs	(131)	(122)
Net unamortized debt premium (discount)	(62)	(24)
Total long-term debt, including current portion	22,414	20,935
Long-term debt due within one year	(47)	(501)
Long-term debt	$22,367	$20,434

Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, and incur additional debt. Default of these agreements could also restrict our ability to make certain distributions or repurchase equity.

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

The following table presents aggregate minimum maturities of long-term debt and other financing obligations, excluding net unamortized debt premium (discount) and debt issuance costs, for each of the next five years:

	December 31, 2018 (Millions)
2019	$ 47
2020	2,138
2021	890
2022	2,021
2023	1,633

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. In the fourth quarter of 2018, Northwest Pipeline filed a registration statement and completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

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 the third quarter of 2018, Transco filed a registration statement and completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

On July 6, 2017, WPZ repaid its $850 million variable interest rate term loan that was due December 2018 using proceeds from the sale of its Geismar Interest.

On June 5, 2017, WPZ issued $1.45 billion of 3.75 percent senior unsecured notes due 2027. WPZ used the proceeds for general partnership purposes, primarily the July 3, 2017 repayment of $1.4 billion of 4.875 percent senior unsecured notes that were due in 2023.

On April 3, 2017, Northwest Pipeline issued $250 million of 4 percent senior unsecured notes due 2027 to investors in a private debt placement. Northwest Pipeline used the net proceeds to retire $185 million of 5.95 percent senior unsecured notes that matured on April 15, 2017, and for general corporate purposes. In the first quarter of 2018, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

On February 23, 2017, using proceeds received from the Financial Repositioning (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies), WPZ early retired $750 million of 6.125 percent senior unsecured notes that were due in 2022.

WPZ retired $600 million of 7.25 percent senior unsecured notes that matured on February 1, 2017.

Other financing obligations

During the construction of the Dalton expansion project, Transco received funding from a partner for its proportionate share of construction costs related to its undivided ownership interest in 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 the third quarter of 2017, Transco began utilizing this partner's undivided interest in the lateral, including the associated pipeline capacity, and reclassified the 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 35 years. Amounts related to this financing obligation included in debt within our Consolidated Balance Sheet were $260 million and $231 million at December 31, 2018 and 2017, respectively.

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 the fourth quarter of 2018, Transco began utilizing this partner's undivided interest in the lateral, including the associated pipeline capacity, and reclassified the 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. At December 31, 2018, $807 million related to this financing obligation was included in debt within our Consolidated Balance Sheet.

Credit Facilities

	December 31, 2018	
	Stated Capacity	Outstanding
	(Millions)	
Long-term credit facility (1)	$4,500	$ 160
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.

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

- 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 alternate 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.

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 December 31, 2018, we are in compliance with these covenants.

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 December 31, 2018 and 2017, no Commercial paper was outstanding. At February 19, 2019, no commercial paper was outstanding.

Cash Payments for Interest (Net of Amounts Capitalized)

Cash payments for interest (net of amounts capitalized) were $1.064 billion in 2018, $1.110 billion in 2017, and $1.152 billion in 2016.

Leases-Lessee

The future minimum annual rentals under noncancelable operating leases, are payable as follows:

	December 31, 2018
	(Millions)
2019	$ 32
2020	31
2021	28
2022	24

2023	15	
Thereafter	86	
Total	$	216

129

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

Total rent expense was $73 million in 2018, $62 million in 2017, and $64 million in 2016 and primarily included in Operating and maintenance expenses and Selling, general, and administrative expenses in the Consolidated Statement of Operations.

Note 15 – Stockholders' Equity

On February 20, 2019, our board of directors approved a regular quarterly dividend of $0.38 per share payable on March 25, 2019.

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 $1.1 million on the shares of Preferred Stock in 2018. Our certificate of incorporation authorizes 30 million shares of Preferred Stock, $1 par value per share.

In January 2017, we issued 65 million shares of common stock in a public offering at a price of $29.00 per share. In February 2017, we issued 9.75 million shares of common stock pursuant to the full exercise of the underwriter’s option to purchase additional shares. The net proceeds of approximately $2.1 billion were used to purchase newly issued common units in WPZ as part of our Financial Repositioning. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies.)

AOCI

The following table presents the changes in AOCI by component, net of income taxes:

	Cash Flow Hedges	Foreign Currency Translation	Pension and Other Post Retirement Benefits	Total
	(Millions)			
Balance at December 31, 2017	$(2)	$ (1)	$ (235)	$(238)
Adoption of new accounting standard (Note 1)	—	—	(61)	(61)
WPZ Merger (Note 1)	(3)	—	—	(3)
Other comprehensive income (loss):				
Other comprehensive income (loss) before reclassifications	(2)	—	(6)	(8)
Amounts reclassified from accumulated other comprehensive income (loss)	5	—	35	40
Other comprehensive income (loss)	3	—	29	32
Balance at December 31, 2018	$(2)	$ (1)	$ (267)	$(270)

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

Reclassifications out of AOCI are presented in the following table by component for the year ended December 31, 2018:

Component	Reclassifications (Millions)	Classification
Cash flow hedges:		
Energy commodity contracts	$ 9	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)	46	Note 10 – Employee Benefit Plans
Total before tax	55	
Income tax benefit	(12)	Provision (benefit) for income taxes
Net of income tax	43	
Noncontrolling interest	(3)	Net income (loss) attributable to noncontrolling interests
Reclassifications during the period	$ 40	

Note 16 – Equity-Based Compensation

Williams' Plan Information

On May 17, 2007, our stockholders approved The Williams Companies, Inc. 2007 Incentive Plan (the Plan) that provides common-stock-based awards to both employees and nonmanagement directors and reserved 19 million new shares for issuance. On May 20, 2010 and May 22, 2014, our stockholders approved amendments and restatements of the Plan to increase by 11 million and 10 million, respectively, the number of new shares authorized for making awards under the Plan, among other changes. The Plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. At December 31, 2018, 24 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 12 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorized up to 2 million new shares of our common stock to be available for sale under the ESPP. On May 22, 2014, our stockholders approved an amendment and restatement of the ESPP to increase by 1.6 million the number of new shares authorized for sale under the ESPP. Employees purchased 338 thousand shares at an average price of $20.70 per share during 2018. Approximately 746 thousand shares were available for purchase under the ESPP at December 31, 2018.

Operating and maintenance expenses and Selling, general, and administrative expenses include equity-based compensation expense for the years ended December 31, 2018, 2017, and 2016 of $54 million, $70 million, and $53 million, respectively. Income tax benefit recognized related to the stock-based compensation expense for the years ended December 31, 2018, 2017, and 2016 was $14 million, $17 million, and $20 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2018, was $56 million, comprised of $4 million related to stock options and $52 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

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

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2018:

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2017	6.6	$ 31.53	
Granted	1.3	$ 29.09	
Exercised	(0.4)	$ 23.06	
Cancelled	(0.2)	$ 31.45	
Outstanding at December 31, 2018	7.3	$ 31.55	$ 6
Exercisable at December 31, 2018	5.3	$ 32.63	$ 6

The following table summarizes additional information related to stock option activity during each of the last three years:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Total intrinsic value of options exercised	$3	$ 4	$ 2
Tax benefits realized on options exercised	$—	$ 1	$ 1
Cash received from the exercise of options	$9	$ 7	$ 4

The weighted-average remaining contractual life for stock options outstanding and exercisable at December 31, 2018, was 5.1 years and 3.7 years, respectively.

The estimated fair value at date of grant of options for our common stock granted in each respective year, using the Black-Scholes option pricing model, is as follows:

	2018	2017	2016
Weighted-average grant date fair value of options for our common stock granted during the year, per share	$5.49	$6.61	$7.90
Weighted-average assumptions:			
Dividend yield	4.7 %	4.2 %	3.2 %
Volatility	30.1 %	35.1 %	44.7 %
Risk-free interest rate	2.7 %	2.1 %	1.2 %
Expected life (years)	6.0	6.0	6.0

The 2018 expected dividend yield is based on the 2018 dividend forecast and the grant-date market price of our stock. Our expected future volatility is determined using the historical volatility of our stock and implied volatility on our traded options. Historical volatility is based on the blended 10-year historical volatility of our stock and certain peer companies. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

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

Nonvested Restricted Stock Units
The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2018:

Restricted Stock Units Outstanding	Shares	Weighted-Average Fair Value (1)
	(Millions)	
Nonvested at December 31, 2017	4.2	$ 31.02
Granted	1.7	$ 30.48
Forfeited	(0.5)	$ 32.97
Vested	(0.9)	$ 39.30
Nonvested at December 31, 2018	4.5	$ 28.96

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(1) Performance-based restricted stock units are valued considering measures of total shareholder return, utilizing a Monte Carlo valuation method, and return on capital employed. All other restricted stock units are valued at the grant-date market price. Restricted stock units generally vest after three years.

Value of Restricted Stock Units	2018	2017	2016
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$30.48	$29.47	$26.51
Total fair value of restricted stock units vested during the year ($s in millions)	$35	$33	$32

Performance-based restricted stock units granted under the Plan represent 34 percent of nonvested restricted stock units outstanding at December 31, 2018. These grants may be earned at the end of the vesting period based on actual performance against a performance target. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

WPZ’s Plan Information

During 2014, certain employees of the general partner of Access Midstream Partners, L.P. (ACMP) received equity-based compensation through ACMP’s equity-based compensation program. These awards were converted to WPZ equity-based awards in accordance with the terms of the February 2, 2015 merger of Williams Partners L.P. with and into Access Midstream Partners, L.P (which was subsequently renamed Williams Partners L.P.). During 2018, no additional grants of restricted common units were awarded through WPZ’s equity-based compensation programs, and all outstanding shares were vested and exercised. Equity-based compensation expense of less than $1 million, $8 million, and $20 million related to WPZ’s equity-based compensation program is included in Operating and maintenance expenses and Selling, general, and administrative expenses for the years ended December 31, 2018, 2017, and 2016, respectively. The total fair value of the restricted common units vested during 2018, 2017, and 2016 was $5 million, $24 million, and $34 million, respectively. This plan is no longer active.

Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk

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, margin deposits, 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.

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

	Carrying Amount	Fair Value	Fair Value Measurements Using: 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 December 31, 2018:					
Measured on a recurring basis:					
ARO Trust investments	$ 150	$ 150	$ 150	$ —	$ —
Energy derivatives assets not designated as hedging instruments	3	3	3	—	—
Energy derivatives liabilities not designated as hedging instruments	(7)	(7)	(4)	—	(3)
Additional disclosures:					
Long-term debt, including current portion	(22,414)	(23,330)	—	(23,330)	—
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:					
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 that is specifically designated to fund future asset retirement obligations. 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 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 years ended December 31, 2018 or 2017.

Additional fair value disclosures

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. The fair values of the financing obligations associated with our Dalton lateral and Atlantic Sunrise projects, which are included within long-term debt, were determined using an income approach (see Note 14 – Debt, Banking Arrangements, and Leases).

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 December 31, 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.

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Notes to Consolidated Financial Statements – (Continued)

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

	Classification	Segment	Date of Measurement	Fair Value	Impairments Years Ended December 31, 2018	2017	2016
				(Millions)			
Certain gathering operations (1)	Property, plant, and equipment – net and Intangible assets - net of accumulated amortization	West	December 31, 2018	$470	$1,849		
Certain idle pipeline assets (2)	Property, plant, and equipment – net	Other	June 30, 2018	25	66		
Certain gathering operations (3)	Property, plant, and equipment – net and Intangible assets - net of accumulated amortization	West	September 30, 2017	439		$1,019	
Certain gathering operations (4)	Property, plant, and equipment – net and Intangible assets - net of accumulated amortization	Northeast G&P	September 30, 2017	21		115	
Certain NGL pipeline (5)	Property, plant, and equipment – net	Other	September 30, 2017	32		68	
Certain olefins pipeline project (6)	Property, plant, and equipment – net	Other	June 30, 2017	18		23	
Canadian operations (7)	Assets held for sale	Other	June 30, 2016	1,130			$747
Certain gathering operations (8)	Property, plant, and equipment – net	West	June 30, 2016	18			48
Certain idle pipeline assets	Property, plant, and equipment – net	Other	December 31, 2016	73			8
Fair value measurements of certain assets					1,915	1,225	803
Other impairments and write-downs (9)					—	23	70
Impairment of certain assets					$1,915	$1,248	$873

Equity-method investments (10)	Investments	Northeast G&P	December 31, 2018	$1,293	$32		
Equity-method investments (11)	Investments	West and Northeast G&P	December 31, 2016	1,295			$318

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Notes to Consolidated Financial Statements – (Continued)

	Classification	Segment	Date of Measurement	Fair Value (Millions)	Impairments Years Ended December 31, 2018	2017	2016
Equity-method investments (12)	Investments	West and Northeast G&P	March 31, 2016	1,294			109
Other equity-method investment	Investments	West	March 31, 2016	—			3
Impairment of equity-method investments					$ 32		$ 430

(1) Relates to our gathering operations in the Barnett Shale. Certain of our contractual gathering rates, primarily those in the Barnett Shale, are based on a percentage of the New York Mercantile Exchange (NYMEX) natural gas prices. During the fourth quarter of 2018, we determined there was a sustained decline in the forward price curves for natural gas. During this same period, a large producer customer in the Barnett Shale removed their remaining drilling rig. These factors gave rise to an impairment evaluation of these assets, which incorporated management's projections of future drilling activity and gathering rates, taking into consideration the information previously noted as well as recently available information regarding producer drilling cost assumptions in the basin. The resulting estimate of future undiscounted cash flows was less than our carrying value, necessitating the estimation of the fair value of these assets. To arrive at the fair value, we utilized an income approach with a discount rate of 8.5 percent, reflecting an estimated cost of capital and risks associated with the underlying assets.

(2) 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 we marketed for sale together with certain other assets. These inputs resulted in a fair value measurement within Level 2 of the fair value hierarchy. We sold these assets in the fourth quarter of 2018. (See Note 3 – Divestitures.)

(3) 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.

(4) 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.

(5) Relates to an NGL pipeline near the Houston Ship Channel region which we anticipated would 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. We sold these assets in the fourth quarter of 2018. (See Note 3 – Divestitures.)

(6) Relates primarily to project development costs associated with an olefins pipeline project in the Gulf Coast region, the likelihood of completion we 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. We sold these assets in the fourth quarter of 2018. (See Note 3 – Divestitures.)

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(7) Relates to our Canadian operations. We designated these operations as held for sale as of June 30, 2016. As a result, we measured the fair value of the disposal group, resulting in an impairment charge. The estimated fair value was determined by a market approach based primarily on inputs received in the marketing process and reflected our estimate of the potential assumed proceeds. We disposed of our Canadian operations through a sale during the third quarter of 2016. (See Note 3 – Divestitures.)

(8) Relates to certain gathering assets within the Mid-Continent region. The estimated fair value was determined by a market approach based on our analysis of observable inputs in the principal market.

(9) 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.

(10) Relates to Northeast G&P's equity-method investment in UEOM. The estimated fair value was determined by a market approach based on our analysis of inputs in the principal market.

(11) Relates to West's previously held interest in Ranch Westex and multiple, currently held Appalachia Midstream Investments at Northeast G&P. The historical carrying value of these equity-method investments was initially recorded based on estimated fair value during the third quarter of 2014 in conjunction with the acquisition of ACMP. We estimated the fair value of these Appalachia Midstream Investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes, rates, and related capital spending. The discount rate utilized for the Appalachia Midstream Investments evaluation was 10.2 percent and reflected an estimated cost of capital as impacted by market conditions and risks associated with the underlying businesses. In addition to utilizing an income approach, we also considered a market approach for certain Appalachia Midstream Investments and Ranch Westex based on an agreement reached in February 2017 to exchange our interests in DBJV and Ranch Westex for additional interests in certain Appalachia Midstream Investments and cash. (See Note 6 – Investing Activities.)

(12) Relates to West's previously held interest in DBJV and Northeast G&P's currently held equity-method investment in Laurel Mountain. Our carrying values in these equity-method investments had been written down to fair value at December 31, 2015. Our first-quarter 2016 analysis reflected higher discount rates for both of these equity-method investments, along with lower natural gas prices for Laurel Mountain. We estimated the fair value of these equity-method investments using an income approach based on expected future cash flows and appropriate discount rates. The determination of estimated future cash flows involved significant assumptions regarding gathering volumes and related capital spending. Discount rates utilized ranged from 13.0 percent to 13.3 percent and reflected increases in the estimated cost of capital, revised estimates of expected future cash flows, and risks associated with the underlying businesses.

Concentration of Credit Risk

Trade accounts and other receivables

The following table summarizes concentration of receivables, net of allowances:

	December 31,	
	2018	2017

	(Millions)	
NGLs, natural gas, and related products and services	$ 626	$ 760
Transportation of natural gas and related products	232	212
Other	134	4
Total	$ 992	$ 976

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Notes to Consolidated Financial Statements – (Continued)

Customers include producers, distribution companies, industrial users, gas marketers, and pipelines primarily located in the continental United States. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly. Based upon this evaluation, we may obtain collateral to support receivables. As of December 31, 2018 and 2017, Chesapeake Energy Corporation, and its affiliates (Chesapeake), a customer primarily within our Northeast G&P and West segments, accounted for $65 million and $176 million, respectively, of the consolidated Trade accounts and other receivables balances. The increase in Other is primarily due to an increase in our federal income tax receivable.

Revenues

In 2018, 2017, and 2016, Chesapeake accounted for 8 percent, 10 percent, and 14 percent, respectively, of our consolidated revenues.

Note 18 – Contingent Liabilities and Commitments

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 the James West case and those of the State of Alaska and North Pole. Several trial dates encompassing all three cases have been scheduled and stricken; we are awaiting a new trial date. 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 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. Although the Court of Chancery scheduled trial for May 20 through May 24, 2019, the parties anticipate trial will be re-scheduled for a later date.

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 December 31, 2018, we have accrued liabilities totaling $35 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 December 31, 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. The EPA previously issued its rule regarding National Ambient Air Quality Standards for ground-level ozone. We are monitoring the rule's implementation as it 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 December 31, 2018, we have accrued liabilities of $6 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 December 31, 2018, we have accrued liabilities totaling $7 million for these costs.

Former operations

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 December 31, 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 December 31, 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.

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Commitments

Commitments for construction and acquisition of property, plant, and equipment are approximately $480 million at December 31, 2018.

Note 19 – 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, Basis of Presentation, and Summary of Significant Accounting Policies.)

Performance Measurement

We evaluate segment operating performance based upon Modified EBITDA (earnings before interest, taxes, depreciation, and amortization). This measure represents the basis of our internal financial reporting and is the primary performance measure used by our chief operating decision maker in 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:
  - 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;
  - 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.

The following geographic area data includes Revenues from external customers based on product shipment origin:

	United States	Canada	Total
	(Millions)		
Revenues from external customers:			
2018	$8,686	$ —	$8,686
2017	8,030	1	8,031
2016	7,425	74	7,499

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The following table reflects the reconciliation of Segment revenues to Total revenues as reported in the Consolidated Statement of Operations and Other financial information:

	Northeast G&P	Atlantic-Gulf	West	Other	Eliminations	Total
	(Millions)					
2018						
Segment revenues:						
Service revenues						
External	$935	$ 2,460	$2,085	$22	$ —	$5,502
Internal	41	49	—	12	(102)	—
Total service revenues	976	2,509	2,085	34	(102)	5,502
Total service revenues – commodity consideration (external only)	20	59	321	—	—	400
Product sales						
External	245	174	2,365	—	—	2,784
Internal	42	261	83	—	(386)	—
Total product sales	287	435	2,448	—	(386)	2,784
Total revenues	$1,283	$ 3,003	$4,854	$34	$ (488)	$8,686
Other financial information:						
Additions to long-lived assets	$477	$ 2,297	$361	$36	$ —	$3,171
Proportional Modified EBITDA of equity-method investments	493	183	94	—	—	770
2017						
Segment revenues:						
Service revenues						
External	$837	$ 2,202	$2,246	$27	$ —	$5,312
Internal	35	37	—	11	(83)	—
Total service revenues	872	2,239	2,246	38	(83)	5,312
Product sales						
External	264	257	1,840	358	—	2,719
Internal	27	227	173	8	(435)	—
Total product sales	291	484	2,013	366	(435)	2,719
Total revenues	$1,163	$ 2,723	$4,259	$404	$ (518)	$8,031
Other financial information:						

Additions to long-lived assets	$460	$ 2,001	$321	$32	$ —	$2,814
Proportional Modified EBITDA of equity-method investments	452	264	79	—	—	795
2016						
Segment revenues:						
Service revenues						
External	$836	$ 1,959	$2,328	$48	$ —	$5,171
Internal	34	39	—	11	(84)	—
Total service revenues	870	1,998	2,328	59	(84)	5,171
Product sales						
External	134	245	1,183	766	—	2,328
Internal	28	205	197	22	(452)	—
Total product sales	162	450	1,380	788	(452)	2,328
Total revenues	$1,032	$ 2,448	$3,708	$847	$ (536)	$7,499
Other financial information:						
Additions to long-lived assets	$223	$ 1,608	$223	$92	$ (1)	$2,145
Proportional Modified EBITDA of equity-method investments	357	287	110	—	—	754

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

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

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Modified EBITDA by segment:			
Northeast G&P	$1,086	$819	$853
Atlantic-Gulf	2,023	1,238	1,621
West	308	412	1,544
Other	(29)	997	(696)
	3,388	3,466	3,322
Accretion expense associated with asset retirement obligations for nonregulated operations	(33)	(33)	(31)
Depreciation and amortization expenses	(1,725)	(1,736)	(1,763)
Equity earnings (losses)	396	434	397
Impairment of equity-method investments	(32)	—	(430)

Other investing income (loss) – net	219	282	63
Proportional Modified EBITDA of equity-method investments	(770)	(795)	(754)
Interest expense	(1,112)	(1,083)	(1,179)
(Provision) benefit for income taxes	(138)	1,974	25
Net income (loss)	$193	$2,509	$(350)

The following table reflects Total assets and Equity-method investments by reportable segments:

	Total Assets		Equity-Method Investments	
	December 31, 2018	December 31, 2017	December 31, 2018	December 31, 2017
	(Millions)			
Northeast G&P	$14,526	$ 14,397	$5,319	$ 5,307
Atlantic-Gulf	16,346	14,989	776	823
West	13,948	16,143	1,726	422
Other (1)	849	1,449	—	—
Eliminations (2)	(367)	(626)	—	—
Total	$45,302	$ 46,352	$7,821	$ 6,552

(1) Decrease in Other is due primarily to a decreased cash balance.

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

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The Williams Companies Inc.
Quarterly Financial Data – (Continued)
(Unaudited)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Millions, except per-share amounts)			
2018				
Revenues	$2,088	$2,091	$2,303	$2,204
Product costs and processing commodity expenses	648	662	820	714
Net income (loss)	270	269	200	(546)
Amounts attributable to The Williams Companies, Inc.:				
Net income (loss)	152	135	129	(571)
Basic earnings (loss) per common share	.18	.16	.13	(.47)
Diluted earnings (loss) per common share	.18	.16	.13	(.47)
2017				
Revenues	$1,988	$1,924	$1,891	$2,228
Product costs	579	537	504	680
Net income (loss)	569	193	125	1,622
Amounts attributable to The Williams Companies, Inc.:				
Net income (loss)	373	81	33	1,687
Basic earnings (loss) per common share	.45	.10	.04	2.04
Diluted earnings (loss) per common share:	.45	.10	.04	2.03

The sum of earnings (loss) per share for the four quarters may not equal the total earnings (loss) per share for the year due to changes in the average number of common shares outstanding and rounding.

2018

Net income (loss) for fourth-quarter 2018 includes:

- $1.849 billion impairment of certain assets in the Barnett Shale region (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements);
- $591 million gain on the sale of our natural gas gathering and processing assets in the Four Corners area of New Mexico and Colorado (see Note 3 – Divestitures);
- $141 million deconsolidation gain associated with our investment in the Brazos Permian II joint venture (see Note 6 – Investing Activities);
- $101 million gain on the sale of certain assets and operations located in the Gulf Coast area (see Note 3 – Divestitures).

2017

Net income (loss) for fourth-quarter 2017 includes:

-

- $1.923 billion benefit for income taxes resulting from Tax Reform rate change (see Note 8 – Provision (Benefit) for Income Taxes);
- $674 million of regulatory charges resulting from Tax Reform and $102 million of charges associated with regulatory asset-related deferred taxes on equity funds used during construction due to Tax Reform (see Note 7 – Other Income and Expenses).

The Williams Companies Inc.
Quarterly Financial Data – (Continued)
(Unaudited)

Net income (loss) for third-quarter 2017 includes:

- $1.095 billion gain on the sale of Williams Olefins, L.L.C., a wholly owned subsidiary which owned our interest in the Geismar, Louisiana, olefins plant (Geismar Interest) (see Note 3 – Divestitures);
- $1.210 billion impairment on certain assets (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk).

Net income (loss) for first-quarter 2017 includes a gain of $269 million associated with the disposition of certain equity-method investments (see Note 6 – Investing Activities).

The Williams Companies, Inc.
Schedule II — Valuation and Qualifying Accounts

	Beginning Balance	Additions Charged (Credited) To Costs and Expenses	Other	Deductions	Ending Balance
	(Millions)				
2018					
Deferred tax asset valuation allowance (1)	$224	$ 96	$ —	$ —	$ 320
2017					
Deferred tax asset valuation allowance (1)	334	(110)	—	—	224
2016					
Deferred tax asset valuation allowance (1)	190	144	—	—	334

(1) Deducted from related assets.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure 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) (Disclosure 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 make modifications as necessary; our intent in this regard is that the Disclosure 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 fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our Internal Control over Financial Reporting.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a - 15(f) and 15d - 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2018, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we concluded that, as of December 31, 2018, our internal control over financial reporting was effective.
Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Stockholders and the Board of Directors of
The Williams Companies, Inc.

Opinion on Internal Control Over Financial Reporting
We have audited The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, The Williams Companies, Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the financial statement schedule listed in the index at Item 15(a) and our report dated February 21, 2019 expressed an unqualified opinion thereon.

Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 21, 2019

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the heading "Election of Directors" in our definitive proxy statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 9, 2019, which shall be filed no later than March 28, 2019 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Questions and Answers About the Annual Meeting and Voting" and "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

We have adopted a Code of Ethics for Senior Officers that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics for Senior Officers, together with our Corporate Governance Guidelines, the charters for each of our board committees, and our Code of Business Conduct applicable to all employees are available on our Internet website at www.williams.com. We will provide, free of charge, a copy of our Code of Ethics or any of our other corporate documents listed above upon written request to our Corporate Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on the corporate governance section of our Internet website at www.williams.com, promptly following the date of any such amendment or waiver.

Item 11. Executive Compensation

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Compensation Discussion and Analysis," "Executive Compensation and Other Information," "Compensation of Directors," "Compensation and Management Development Committee Report on Executive Compensation," and "Compensation and Management Development Committee Interlocks and Insider Participation" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation and Management Development Committee Report on Executive Compensation" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading “Corporate Governance and Board Matters” in our Proxy Statement, which information is incorporated by reference herein.

Item 14. Principal Accountant Fees and Services

The information regarding our principal accounting fees and services required by Item 9(e) of Schedule 14A will be presented under the heading “Principal Accountant Fees and Services” in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. Exhibits and Financial Statement Schedules
(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.
(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
2.1+	—	Agreement and Plan of Merger dated as of May 12, 2015, by and among The Williams Companies, Inc., SCMS LLC, Williams Partners, L.P., and WPZ GP LLC (filed on May 13, 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).
2.2	—	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).

Exhibit No.		Description
2.4	—	Interest Swap and Purchase Agreement by and among Western Gas Partners, LP, WGR Operating, LP, Delaware Basin JV Gathering LLC, Williams Partners L.P., Williams Midstream Gas Services LLC, and Appalachia Midstream Services, L.L.C., dated February 9, 2017 (filed on February 10, 2017, 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).
2.5	—	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, (filed on May 26, 2010, as Exhibit 3.(i)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 July17, 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	—	Senior Indenture, dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on February 25, 1997, as Exhibit 4.5.1 to MAPCO Inc.'s Amendment No. l to registration statement on Form S-3 (File No. 333-20837) and incorporated herein by reference).
4.2	—	Supplemental Indenture No. 1, dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 4, 1998 as Exhibit 4(o) to MAPCO Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1997 (File No. 001-05254) and incorporated herein by reference).
4.3	—	Supplemental Indenture No. 2, dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 4, 1998, as Exhibit 4(p) to MAPCO Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1997 (File No. 001-05254) and incorporated herein by reference).
4.4	—	Supplemental Indenture No. 3, dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 30, 1999, as Exhibit 4(J) to Williams Holdings of Delaware, Inc.'s annual report on Form 10-K for the fiscal year ended December 31, 1998 (File No. 000-20555) and incorporated herein by reference).

4.5	—	Fourth Supplemental Indenture, dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., The Williams Companies, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 28, 2000, as Exhibit 4(q) to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
4.6	—	Fifth Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010, as Exhibit 4.3 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).

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Exhibit No.	Description
4.7	Fifth Supplemental Indenture between The Williams Companies, Inc. and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001, as Exhibit 4(k) to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
4.8	Seventh Supplemental Indenture, dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed on May 9, 2002, as Exhibit 4.1 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
4.9	Eleventh Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010, 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).
4.10	Indenture, dated as of March 5, 2009, among The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (filed on March 11, 2009, 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).
4.11	First Supplemental Indenture, dated as of February 1, 2010, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010, 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).
4.12	Indenture, dated December 18, 2012, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012, 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).
4.13	First Supplemental Indenture, dated December 18, 2012, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. as trustee (filed on December 20, 2012, 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).
4.14	Second Supplemental Indenture, dated as of June 24, 2014, between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on June 24, 2014, 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).
4.15	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010, 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).
4.16	First Supplemental Indenture, dated as of February 2, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 3, 2015, as Exhibit 4.5 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.17	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).
4.18	Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).

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Exhibit No.		Description
4.19	—	First Supplemental Indenture, dated as of November 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on November 12, 2010, as Exhibit 4.2 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.20	—	Second Supplemental Indenture, dated as of November 17, 2011, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed November 18, 2011, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.21	—	Third Supplemental Indenture (including Form of 3.35% Senior Notes due 2022), dated as of August 14, 2012, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 14, 2012 as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.22	—	Fourth Supplemental Indenture, dated as of November 15, 2013, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N .A., as trustee (filed on November 18, 2013, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.23	—	Fifth Supplemental Indenture, dated as of March 4, 2014, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 4, 2014, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.24	—	Sixth Supplemental Indenture, dated as of June 27, 2014, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on June 27, 2014, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
4.25	—	Seventh Supplemental Indenture, dated as of February 2, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 3, 2015, as Exhibit 4.4 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.26	—	Eighth Supplemental Indenture, dated as of March 3, 2015, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 3, 2015, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.27	—	Ninth Supplemental Indenture, dated as of June 5, 2017, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee. (filed on June 5, 2017, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.28	—	Tenth Supplemental Indenture, dated as of March 5, 2018, between Williams Partners L.P. and The bank of New York Mellon Trust Company, N.A., as trustee (filed on March 5, 2018, as Exhibit 4.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-34831) and incorporated herein by reference).
4.29	—	

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).

Exhibit No.		Description
4.30	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee (filed September 14, 1995, as Exhibit 4.1 to Northwest Pipeline's registration statement on Form S-3 (File No. 033-62639) and incorporated herein by reference).
4.31	—	Indenture, dated as of April 3, 2017, between Northwest Pipeline LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on April 3, 2017, as Exhibit 4.1 to Northwest Pipeline's current report on Form 8-K (File No. 001-07414) and incorporated herein by reference).
4.32	—	Senior Indenture, dated as of July 15, 1996, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996, as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's registration statement on Form S-3 (File No. 333-02155) and incorporated herein by reference).
4.33	—	Indenture, dated as of August 12, 2011, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on August 12, 2011, as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's current report on Form 8-K (File No. 001-07584) and incorporated herein by reference).
4.34	—	Indenture, dated as of July 13, 2012, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on July 16, 2012 as Exhibit 4.1 to Transcontinental Gas Pipe Line Company, LLC's current report on Form 8-K (File No. 001-07584) and incorporated herein by reference).
4.35	—	Indenture, dated as of January 22, 2016, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on January 22, 2016, 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).
4.36	—	Indenture, dated as of March 15, 2018, between Transcontinental Gas Pipe Line Company, LLC and The Bank of New York Mellon Trust Company, N.A., as trustee (filed on March 15, 2018, as Exhibit 4.1 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated by reference).
10.1§	—	The Williams Companies Amended and Restated Retirement Restoration Plan effective as of December 1, 2017 (filed on February 22, 2018, as Exhibit 10.1 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.2§	—	Form of Director and Officer Indemnification Agreement (filed on September 24, 2008, 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).
10.3§	—	Form of 2013 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 27, 2013, as Exhibit 10.6 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.4§	—	

		Form of 2013 Restricted Stock Unit Agreement among Williams and certain nonmanagement directors (filed on February 26, 2014, as Exhibit 10.11 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.5§	—	Form of 2014 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 26, 2014, as Exhibit 10.8 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.6§	—	Form of 2014 Restricted Stock Unit Agreement among Williams and certain nonmanagement directors (filed on February 25, 2015, as Exhibit 10.12 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
10.7§	—	Form of 2015 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 25, 2015, as Exhibit 10.15 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.8§	—	Form of 2015 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 25, 2015, as Exhibit 10.16 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.9§	—	Form of 2015 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 25, 2015, as Exhibit 10.17 to The Williams Companies, Inc. annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.10§	—	Form of 2015 Non-Equity Incentive Award Agreement among The Williams Companies Inc. and certain employees and officers (filed on October 29, 2015, as Exhibit 10.3 to The Williams Companies, Inc. quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.11§	—	Form of 2016 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017, as Exhibit 10.18 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.12§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017, as Exhibit 10.19 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.13§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers vesting February 22, 2019 (filed on February 22, 2017, as Exhibit 10.20 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.14§	—	Form of 2016 Time-Based Restricted Stock Unit Agreement among Williams and certain non-management directors (filed on February 22, 2017, as Exhibit 10.21 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.15§	—	Form of 2016 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 22, 2017, as Exhibit 10.22 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.16§	—	Form of 2017 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 22, 2017, as Exhibit 10.23 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.17§	—	Form of 2017 Time-Based Restricted Stock Unit Agreement among Williams and certain non-management directors (filed on February 22, 2017, as Exhibit 10.24 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.18§	—	Form of 2017 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 22, 2017, as Exhibit 10.25 to The Williams Companies, Inc.'s annual report on Form

10-K (File No. 001-04174) and incorporated herein by reference).

10.19§	Form of 2017 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on May 4, 2017, as Exhibit 10.10 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.20§	Form of 2018 Time-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on May 3, 2018, as Exhibit 10.3 to The Williams Companies Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).

Exhibit No.		Description
10.21§	—	Form of 2018 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on May 3, 2018, as Exhibit 10.4 to The Williams Companies Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.22§	—	Form of 2018 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on May 3, 2018, as Exhibit 10.5 to The Williams Companies Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.23§	—	Form of 2018 Time-Based Restricted Stock Unit Agreement among Williams and certain non-management directors (filed on August 2, 2018, as Exhibit 10.2 to The Williams Companies Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.24§	—	The Williams Companies, Inc. 1996 Stock Plan for Nonemployee Directors (filed on March 27, 1996, as Exhibit B to The Williams Companies, Inc.'s Definitive Proxy Statement (File No. 002-27038) and incorporated herein by reference).
10.25§	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed on August 5, 2004, as Exhibit 10.1 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).
10.26§	—	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009, as Exhibit 10.11 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.27§	—	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009, as Exhibit 10.12 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.28§*	—	Change in Control and Restrictive Covenant Agreement between certain executive officers (Tier One Executives) and The Williams Companies, Inc.
10.29§*	—	Change in Control and Restrictive Covenant Agreement between certain executive officers (Tier Two Executives) and The Williams Companies, Inc.
10.30§	—	The Williams Companies, Inc. Executive Severance Pay Plan, dated November 14, 2012 (filed July 20, 2016, as Exhibit 10.2 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.31§	—	First Amendment to The Williams Companies Inc. Executive Severance Pay Plan (filed July 20, 2016, 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).
10.32	—	Separation and Distribution Agreement dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (Filed on February 28, 2012, as Exhibit 10.19 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).

10.33	—	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (filed on January 6, 2012, as Exhibit 10.3 to The Williams Companies, Inc.'s current report on Form 8-K (File No. 001-04174) and incorporated herein by reference).
10.34§	—	Letter Agreement, dated January 27, 2014, with James E. Scheel, Senior Vice President - Northeast G&P, regarding Relocation from Pennsylvania Benefits (filed on May 1, 2014, as Exhibit 10.2 to The Williams Companies, Inc.'s quarterly report on Form 10-Q (File No. 001-04174) and incorporated herein by reference).

Exhibit No.	Description
10.35§	The Williams Companies, Inc. 2007 Incentive Plan as amended and restated effective July 14, 2016 (filed on February 22, 2017, as Exhibit 10.38 to The Williams Companies, Inc.'s annual report on Form 10-K (File No. 001-04174) and incorporated herein by reference).
10.36	Credit Agreement dated as of July 13, 2018, between The Williams Companies, Inc., Northwest Pipeline LLC, and Transcontinental Gas Pipe Line 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).
10.37	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).
10.38	Common Unit Issuance Agreement, dated January 9, 2017 (filed on January 10, 2017, as Exhibit 2 to Schedule 13D/A (File No. 005-86017) by The Williams Companies, Inc. relating to the common units representing limited partner interests of Williams Partners L.P. and incorporated herein by reference).
10.39	Registration Rights Agreement, dated March 15, 2018, among Transcontinental Gas Pipe line Company, LLC and the initial purchasers listed therein (filed on March 15, 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).
10.40	Common Unit Purchase Agreement, dated January 9, 2017 (filed on January 10, 2017, as Exhibit 3 to Schedule 13D/A (File No. 005-86017) by The Williams Companies, Inc. relating to the common units representing limited partner interests of Williams Partners L.P. and incorporated herein by reference).
14	Code of Ethics for Senior Officers (filed on March 15, 2004, as Exhibit 14 to The Williams Companies, Inc.'s annual report on Form 10-K and incorporated herein by reference).
21*	Subsidiaries of the registrant.
23.1*	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2*	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.3*	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP.
31.1*	Certification of the Chief Executive Officer pursuant to Rules 13a-l 4(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(3 l) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Chief Financial Officer pursuant to Rules 13a-14(a) and l 5d-l 4(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 the Chief Executive Officer and the 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.

Exhibit No.	Description
101.DEF*	—XBRL Taxonomy Extension Definition Linkbase.
101.LAB*	—XBRL Taxonomy Extension Label Linkbase.
101.PRE*	—XBRL Taxonomy Extension Presentation Linkbase.

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* Filed herewith

** Furnished herewith

§ Management contract or compensatory plan or arrangement

\+ Pursuant to item 601(6)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Item 16. Form 10-K Summary
Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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)

By: /s/ TED T. TIMMERMANS
Ted T. Timmermans
Vice President, Controller and
Chief Accounting Officer
Date: February 21, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ALAN S. ARMSTRONG Alan S. Armstrong	President, Chief Executive Officer and Director (Principal Executive Officer)	February 21, 2019
/s/ JOHN D. CHANDLER John D. Chandler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2019
/s/ TED T. TIMMERMANS Ted T. Timmermans	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 21, 2019
/s/ STEPHEN W. BERGSTROM Stephen W. Bergstrom	Chairman of the Board	February 21, 2019
/s/ NANCY K. BUESE Nancy K. Buese	Director	February 21, 2019
/s/ STEPHEN I. CHAZEN Stephen I. Chazen	Director	February 21, 2019
/s/ CHARLES I. COGUT Charles I. Cogut	Director	February 21, 2019
/s/ KATHLEEN B. COOPER Kathleen B. Cooper	Director	February 21, 2019
/s/ MICHAEL A. CREEL Michael A. Creel	Director	February 21, 2019
/s/ VICKI L. FULLER Vicki L. Fuller	Director	February 21, 2019
/s/ PETER A. RAGAUSS Peter A. Ragauss	Director	February 21, 2019

Signature	Title	Date
/s/ SCOTT D. SHEFFIELD Scott D. Sheffield	Director	February 21, 2019
/s/ MURRAY D. SMITH Murray D. Smith	Director	February 21, 2019
/s/ WILLIAM H. SPENCE William H. Spence	Director	February 21, 2019