WILLIAMS COMPANIES INC
Form 10-K
February 26, 2016

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, 2015
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
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
5.50% Junior Subordinated Convertible Debentures due 2033

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if a smaller reporting company)

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 $39,345,468,396.

The number of shares outstanding of the registrant's common stock outstanding at February 22, 2016 was 750,065,665.

DOCUMENTS INCORPORATED BY REFERENCE

None

THE WILLIAMS COMPANIES, INC.
FORM 10-K

TABLE OF CONTENTS

PART IV

DEFINITIONS

The following is a listing of certain abbreviations, acronyms and other industry terminology 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 approximately one trillion British thermal units
MMdth/d: One million dekatherms per day
Tbtu: One trillion British thermal units
Consolidated Entities:
ACMP: Access Midstream Partners, L.P. prior to its merger with Pre-Merger WPZ
Cardinal: Cardinal Gas Services, L.L.C.
Constitution: Constitution Pipeline Company, LLC
Gulfstar One: Gulfstar One LLC
Jackalope: Jackalope Gas Gathering Services, L.L.C.
Pre-merger WPZ: Williams Partners L.P. prior to its merger with ACMP
Northwest Pipeline: Northwest Pipeline LLC
Transco: Transcontinental Gas Pipe Line Company, LLC
WPZ: Williams Partners L.P.
Partially Owned Entities: Entities in which we do not own a 100 percent ownership interest and which, as of December 31, 2015, we account for as an equity-method investment, including principally the following:
Aux Sable: Aux Sable Liquid Products LP
Bluegrass: Bluegrass Pipeline Company LLC
Caiman II: Caiman Energy II, LLC
Discovery: Discovery Producer Services LLC
Gulfstream: Gulfstream Natural Gas System, L.L.C.
Laurel Mountain: Laurel Mountain Midstream, LLC
Moss Lake: Moss Lake Fractionation LLC and Moss Lake LPG Terminal LLC
OPPL: Overland Pass Pipeline Company LLC
UEOM: Utica East Ohio Midstream LLC

Government and Regulatory:
Code, the: Internal Revenue Code of 1986
EPA: Environmental Protection Agency
Exchange Act, the: Securities and Exchange Act of 1934, as amended
FERC: Federal Energy Regulatory Commission
IRS: Internal Revenue Service
SEC: Securities and Exchange Commission
Other:
Energy Transfer: Energy Transfer Equity, L.P.
ETC: Energy Transfer Corp LP
Merger Agreement: Merger Agreement and Plan of Merger of Williams with Energy Transfer and certain of its affiliates
ETC Merger: Merger wherein Williams will be merged into ETC
CCR: Contingent consideration right
Caiman Acquisition: WPZ’s April 2012 purchase of 100 percent of Caiman Eastern Midstream, LLC located in the Ohio River Valley area of the Marcellus Shale region
Fractionation: The process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane, and butane
IDR: Incentive distribution right
Laser Acquisition: WPZ’s February 2012 purchase from Delphi Midstream Partners, LLC of 100 percent of certain entities that operate in Susquehanna County, PA and southern New York
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
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

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. You may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC’s Internet website at www.sec.gov.

Our Internet website is www.williams.com. We make available free of charge through the Investor 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, 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 primarily an energy infrastructure company focused on connecting North America’s significant hydrocarbon resource plays to markets for natural gas, NGLs, and olefins. Our operations are located principally in the United States, but span from the deepwater Gulf of Mexico to the Canadian oil sands.

As of December 31, 2015, our interstate gas pipelines, midstream, and olefins production interests were largely held through our significant investment in Williams Partners L.P. (WPZ). We own the general partner interest and a 58 percent limited-partner interest in WPZ.

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; Oklahoma City, Oklahoma; Pittsburgh, Pennsylvania; Calgary, Alberta; and the Four Corners Area. Our telephone number is 918-573-2000.

DIVIDENDS

We increased our quarterly dividends from $0.57 per share in the fourth quarter of 2014 to $0.64 per share in the fourth quarter of 2015.

ENERGY TRANSFER MERGER AGREEMENT

On September 28, 2015, we entered into a Merger Agreement with Energy Transfer and certain of its affiliates. The Merger Agreement, subject to approval of our stockholders and certain regulatory approvals, provides that we will be merged with and into the newly formed ETC with ETC surviving the ETC Merger. Energy Transfer formed ETC as a limited partnership that will be treated as a corporation for U.S. federal income tax purposes. ETC will be publicly traded on the New York Stock Exchange under the symbol “ETC.”

At the effective time of the ETC Merger, each issued and outstanding share of our common stock (except for certain shares such as those held by us or our subsidiaries and any held by ETC and its affiliates) will be canceled and automatically converted into the right to receive stock, cash, or a combination of both, at the election of each holder and subject to proration as set forth in the Merger Agreement. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies for additional information.)

FINANCIAL INFORMATION ABOUT SEGMENTS

See "Item 8 — Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements — Note 19 – Segment Disclosures".

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. Our activities in 2015 were primarily operated through the following business segments as presented in the accompanying financial statements and management's discussion and analysis.

- Williams Partners — comprised of our consolidated master limited partnership, WPZ, which includes gas pipeline and midstream businesses. The gas pipeline business includes interstate natural gas pipelines and pipeline joint project investments. The midstream business provides natural gas gathering, treating, processing and compression services; NGL production, fractionation, storage, marketing and transportation; deepwater production handling and crude oil transportation services; an olefin production business and is comprised of several wholly owned and partially owned subsidiaries and joint project investments.

Our Canadian midstream operations include an oil sands offgas processing plant near Fort McMurray, Alberta, an NGL/olefin fractionation facility, and the Boreal Pipeline.

- Williams NGL & Petchem Services — comprised of our Texas Belle pipeline and certain other domestic olefins pipeline assets and certain Canadian growth projects under development, including a propane dehydrogenation facility and a liquids extraction plant.
- Other — primarily comprised of corporate operations and our Canadian construction services company.

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

Williams Partners

Gas Pipeline Business

Williams Partners' gas pipeline businesses consist primarily of Transco and Northwest Pipeline. Our gas pipeline business also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent equity-method investment in Gulfstream and a 41 percent interest in Constitution (a consolidated entity), which is under development. Transco and Northwest Pipeline own and operate a combined total of approximately13,600 miles of pipelines with a total annual throughput of approximately 4,136 TBtu of natural gas and peak-day delivery capacity of approximately 15.4 MMdth of natural gas.

Transco

Transco is an interstate natural gas transmission company that owns and operates a 9,700-mile natural gas pipeline system, which is regulated by the FERC, extending from Texas, Louisiana, Mississippi and the offshore 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.

Pipeline system and customers

At December 31, 2015, Transco's system had a mainline delivery capacity of approximately 6.4 MMdth of natural gas per day from its production areas to its primary markets, including delivery capacity from the mainline to locations on its Mobile Bay Lateral. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 5.1MMdth of natural gas per day for a system-wide delivery capacity total of approximately 11.5 MMdth of natural gas per day. Transco’s system includes 45 compressor stations, four underground storage fields, and an LNG storage facility. Compression facilities at sea level-rated capacity total approximately 1.8 million horsepower.

Transco’s major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco’s system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, natural gas marketers and producers. Transco’s firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco’s business. Additionally, Transco offers interruptible transportation services under shorter-term agreements.

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. At December 31, 2015, Transco’s customers had stored in its facilities approximately 161 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.

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.

Pipeline system and customers

At December 31, 2015, Northwest Pipeline’s system, having long-term firm transportation and storage redelivery agreements with aggregate capacity reservations of approximately 3.8 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 transports and stores natural gas for a broad mix of customers, including local natural gas distribution companies, municipal utilities, direct industrial users, electric power generators, and natural gas marketers and producers. Northwest Pipeline’s firm transportation and storage redelivery contracts are generally long-term contracts with various expiration dates and account for the major portion of Northwest Pipeline’s business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

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.

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. Williams Partners owns, through a subsidiary, a 50 percent equity-method investment in Gulfstream. Williams Partners shares operating responsibilities for Gulfstream with the other 50 percent owner.

6

Midstream Business

Williams Partners' midstream business, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in major producing basins in Arkansas, Colorado, New Mexico, Oklahoma, Texas, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio. The primary businesses are: (1) natural gas gathering, treating, and processing; (2) NGL fractionation, storage and transportation; (3) crude oil transportation; and (4) olefins production. These fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer. We also own and operate gas gathering and processing assets and pipelines primarily within the onshore, offshore shelf, and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama.

Key variables for this business will continue to be:

- Producer drilling activities impacting natural gas supplies supporting our gathering and processing volumes;
- Prices impacting 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 core service areas and new step-out areas;

Gathering, Processing, and Treating

Williams Partners' 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. Williams Partners' treating facilities remove water vapor, carbon dioxide, and other contaminants and collect condensate, but do not extract NGLs. Williams Partners' is 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 domestic gas processing services generate revenues primarily from the following three 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 revenues includes a share of the margins on the NGLs produced. For the year ended December 31, 2015, 76 percent of the NGL production volumes were under fee-based contracts.
- Keep-whole: Under keep-whole contracts, we (1) process natural gas produced by customers, (2) retain some or all of the extracted NGLs as compensation for our services, (3) replace the Btu content of the retained NGLs

that were extracted during processing with natural gas purchases, also known as shrink replacement gas, and (4) deliver an equivalent Btu content of natural gas for customers at the plant outlet. NGLs we retain in connection with this type of processing agreement are referred to as our equity NGL production. Under these agreements, we have commodity price exposure on the difference between NGL and natural gas prices. For the year ended December 31, 2015, 20 percent of the NGL production volumes were under keep-whole contracts.

- Percent-of-Liquids: Under percent-of-liquids processing contracts, we (1) process natural gas produced by customers, (2) deliver to customers an agreed-upon percentage of the extracted NGLs, (3) retain a portion of the extracted NGLs as compensation for our services, and (4) deliver natural gas to customers at the plant outlet. Under this type of contract, we are not required to replace the Btu content of the retained NGLs that were extracted during processing, and are therefore only exposed to NGL price movements. NGLs we retain in connection with this type of processing agreement are also referred to as our equity NGL production. For the year ended December 31, 2015, 4 percent of the NGL production volumes were under percent-of-liquids 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, compression and other expenses. Our gas gathering agreements with two major customers include MVCs covering their respective producing regions. If the minimum annual or semi-annual volume commitment is not met, these customers are obligated to pay a fee equal to the applicable fee for each Mcf by which the applicable customer’s minimum annual or semi-annual volume commitment exceeds the actual volume gathered. The revenue associated with such shortfall fees is recognized in the fourth quarter of each year.

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. Williams Partners’ gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding its infrastructure. During 2015, Williams Partners’ facilities gathered and processed gas for approximately 230 customers. Williams Partners’ top six gathering and processing customers accounted for approximately 74 percent of our gathering and processing fee revenue and NGL margins from our keepwhole and percent-of-liquids 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 been shifting away from the more expensive crude-based feedstocks.

Geographically, the midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of the offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Our San Juan basin, southwest Wyoming, and Piceance systems are capable of delivering residue gas volumes into Northwest Pipeline’s interstate system in addition to third-party interstate systems. Our gathering systems in Pennsylvania delivers residue gas volumes into Transco’s pipeline in addition to third-party interstate systems.

The following table summarizes our significant consolidated natural gas gathering assets:

Natural Gas Gathering Assets	Location	Pipeline Miles	Inlet Capacity (Bcf/d)	Ownership Interest	Supply Basins/Shale Formations
Central					
Barnett Shale	Texas	860	0.9	100%	Barnett Shale
Eagle Ford Shale	Texas	1,118	0.7	100%	Eagle Ford Shale
Haynesville Shale	Louisiana	592	1.7	100%	Haynesville Shale
Permian	Texas	346	0.1	100%	Permian
Mid-Continent	Arkansas, Oklahoma, Texas	2,112	0.9	100%	Miss-Lime, Granite Wash, Colony Wash
Northeast					
Ohio Valley	West Virginia & Pennsylvania	210	0.8	100%	Appalachian
Susquehanna Supply Hub	Pennsylvania & New York	370	2.7	100%	Appalachian
Cardinal (1)	Ohio	349	1.0	66%	Appalachian
Atlantic-Gulf					
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	120	0.9	100%	Western Gulf of Mexico
West					
Four Corners	Colorado & New Mexico	3,743	1.8	100%	San Juan
Wamsutter	Wyoming	1,973	0.6	100%	Wamsutter
Southwest Wyoming	Wyoming	1,614	0.5	100%	Southwest Wyoming
Piceance	Colorado	336	1.5	(2)	Piceance
Niobrara	Wyoming	184	0.2	(3)	Powder River

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

(2) Includes our 60 percent ownership of a gathering system in the Ryan Gulch area with 140 miles of pipeline and 200 MMcf/d of inlet capacity, and our 67 percent ownership of a gathering system at Allen Point with 8 miles of pipeline and 60 MMcf/d of inlet capacity. We operate both systems. We own and operate 100 percent of the balance of the Piceance gathering assets.

(3) Includes our 50 percent ownership of the Jackalope gathering system, which we operate, with 184 miles of pipeline and 165 MMcf/d of inlet capacity.

The following table summarizes our significant consolidated natural gas processing facilities:

Natural Gas Processing Facilities

	Location	Inlet Capacity (Bcf/d)	NGL Production Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Northeast					
Fort Beeler	Marshall County, WV	0.5	62	100%	Appalachian
Oak Grove	Marshall County, WV	0.2	25	100%	Appalachian
Atlantic-Gulf					
Markham	Markham, TX	0.5	45	100%	Western Gulf of Mexico
Mobile Bay	Coden, AL	0.7	30	100%	Eastern Gulf of Mexico
West					
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
Ignacio	Ignacio, CO	0.5	29	100%	San Juan
Kutz	Bloomfield, NM	0.2	12	100%	San Juan
Bucking Horse (1)	Converse County, WY	0.1	7	50%	Powder River
Parachute	Garfield County, CO	1.2	6	100%	Piceance

(1) Statistics reflect 100 percent of the assets from our 50 percent ownership of Bucking Horse gas processing facility.

In addition, we own and operate several natural gas treating facilities in New Mexico, Colorado, Texas, and Louisiana which bring natural gas to specifications allowable by major interstate pipelines.

We also own and operate fractionation facilities at Moundsville, de-ethanization and condensate facilities at our Oak Grove processing plant, another condensate stabilization facility near our Oak Grove plant, and an ethane transportation pipeline. Our two condensate stabilizers are capable of handling more than 14 Mbbls/d of field condensate. NGLs are extracted from the natural gas stream in our 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. The remaining mixed NGL stream from the de-ethanizer is then transported and fractionated at our Moundsville facilities, which are capable of handling more than 42 Mbbls/d of mixed NGLs. Ethane produced at our de-ethanizer is transported to markets via our 50-mile ethane pipeline from Oak Grove to Houston, Pennsylvania.

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 crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of our marketing revenues are recognized from purchase and sale arrangements whereby the oil that we transport is purchased and sold as a function of the same index-based price. Our offshore floating production platforms provide centralized services to deepwater producers such as compression, separation, production handling, water removal, and pipeline landings. 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.

The following tables summarize our significant crude oil transportation pipelines and production handling platforms:

	Crude Oil Pipelines			
	Pipeline Miles	Capacity (Mbbls/d)	Ownership Interest	Supply Basins
Mountaineer, including Blind Faith and Gulfstar extensions	172	150	100%	Eastern Gulf of Mexico
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

	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.

Canadian Operations

Our Canadian operations include 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 transports NGLs and associated olefins from our Fort McMurray plant to our Redwater fractionation facility. We operate the Fort McMurray area processing plant and the Boreal Pipeline, while another party operates the Redwater facilities on our behalf. Our Fort McMurray area facilities extract liquids from the offgas produced by a third-party oil sands bitumen upgrader. Our arrangement with the third-party upgrader is a “keep-whole” type where we remove a mix of NGLs and olefins from the offgas and return the equivalent heating value to the third-party upgrader in the form of natural gas, as well as a profit share whereby a portion of the profit above a threshold is shared with the third party. We extract, fractionate, treat, store, terminal and sell the ethane/ethylene, propane, propylene, normal butane (butane), iso-butane, alky feedstock, and condensate recovered from this process. The commodity price exposure of this asset is the spread between the price for natural gas and the NGL and olefin products we produce. We continue to be the only NGL/olefins fractionator in western Canada and the only processor of oil sands upgrader offgas. Our extraction of liquids from upgrader offgas streams allows the upgraders to burn cleaner natural gas streams and reduces their overall air emissions.

The Fort McMurray extraction plant has processing capacity of 121 MMcf/d with the ability to recover 26 Mbbls/d of olefin and NGL products. Our Redwater fractionator has a liquids handling capacity of 26 Mbbls/d. We also purchase small volumes of olefin/NGLs mixes from third-party gas processors, fractionate the olefins and NGLs at our Redwater plant and sell the resulting products. The Boreal Pipeline is a 261-mile pipeline in Canada that transports recovered NGLs and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline has an initial capacity of 43 Mbbls/d that can be increased to an ultimate capacity of 125 Mbbls/d with additional pump stations. Our products are sold within Canada and the United States.

Operating Statistics

The following table summarizes our significant operating statistics:

	2015	2014	2013
Volumes:			
Canadian propylene sales (millions of pounds)	161	143	118
Canadian NGL sales (millions of gallons)	284	218	123

11

Gulf Olefins

We have an 88.5 percent undivided interest and operatorship of the olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter, and pipelines in the Gulf region. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage caverns.

In 2015, we placed in service an expansion of the olefins production facility that increased its ethylene production capacity by 600 million pounds per year, for a total production capacity of 1.95 billion pounds of ethylene and 114 million pounds of propylene per year. Our feedstocks for the cracker are ethane and propane; as a result, these assets are primarily exposed to the price spread between ethane and propane, and ethylene and propylene, respectively. Ethane and propane are available for purchase from third parties and from affiliates. We own ethane and propane pipeline systems in Louisiana that provide feedstock transportation to the Geismar plant and other third-party crackers. We also own a pipeline that has the capacity to supply 12 Mbbls/d of ethane from Discovery's Paradis fractionator to the Geismar plant. Following an explosion and fire that occurred in 2013, the Geismar plant resumed consistent operations in late March 2015 and reached full production capacity in the third quarter of 2015.

Our refinery grade propylene splitter has a production capacity of approximately 500 million pounds per year of propylene. At our propylene splitter, we purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result, this asset is exposed to the price spread between those commodities.

As a merchant producer of ethylene and propylene, our product sales are to customers for use in making plastics and other downstream petrochemical products destined for both domestic and export markets.

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. Other than a long-term agreement to sell our equity NGLs transported on OPPL, the majority of sales are based on supply contracts of one year or less in duration.

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

We also market olefin products to a wide range of users in the energy and petrochemical industries. In order to meet sales contract obligations, we may purchase olefin products for resale.

Other NGL & Petchem 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.

We own approximately 115 miles of pipelines in the Houston Ship Channel area which transport a variety of products including ethane, propane, ammonia, tertiary butyl alcohol, and other industrial products used in the petrochemical industry. We also own a tunnel crossing pipeline under the Houston Ship Channel. A portion of these pipelines are leased to third parties.

We own the roughly 280-mile Bayou Ethane Pipeline, which operates between Texas and Louisiana. The pipeline connects a 57-mile pipeline segment from Mont Belvieu to Port Arthur, Texas, and a 50-mile pipeline segment from Lake Charles, Louisiana, to Port Arthur. The pipeline provides ethane transportation capacity from fractionation and storage facilities in Mont Belvieu, Texas, to the WPZ Geismar olefins plant in south Louisiana and serves customers along the way.

We also own a 14.6 percent equity-method investment 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 107 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.

WPZ Operating Areas

Effective January 1, 2016, WPZ organizes these businesses into the following operating areas:

Central is comprised of domestic gathering, treating, and compression services to producers under long-term, fixed fee contracts. Its primary operating areas are in 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. Central also includes a 50 percent equity-method investment in the Delaware basin gas gathering system in the Permian region.

Northeast G&P is comprised of natural gas gathering and processing and NGL fractionation businesses in the Marcellus Shale region primarily in Pennsylvania, New York, and West Virgina and the Utica Shale region of eastern Ohio, as well as 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 an approximate average 45 percent equity-method investment in multiple gas gathering systems in the Marcellus Shale (Appalachia Midstream Investments).

Atlantic-Gulf is comprised of an interstate natural gas pipeline, Transco, and significant natural gas gathering and processing and crude oil production handling and transportation in the Gulf Coast region, including a 51 percent interest in Gulfstar One (a consolidated entity) which is a proprietary floating production system, as well as a 50 percent equity-method investment in Gulfstream, a 41 percent interest in Constitution (a consolidated entity) which is under development, and a 60 percent equity-method investment in Discovery.

West is comprised of the natural gas gathering, processing, and treating operations in New Mexico, Colorado, and Wyoming and an interstate natural gas pipeline, Northwest Pipeline.

NGL & Petchem Services is comprised of our 88.5 percent undivided interest in an olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and various petrochemical and feedstock pipelines in the Gulf Coast region, an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility. 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, and a 50 percent equity-method investment in OPPL.

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 614-mile offshore natural gas gathering and transportation system in the Gulf of Mexico with an inlet capacity of 1,350 MMcf/d, including the Keathley Canyon Connector, a 209-mile deepwater lateral pipeline in the central deepwater Gulf of Mexico that contributed 400 MMcf/d of inlet capacity when it was placed in service in late 2014. 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.

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 0.7 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 688 miles of natural gas gathering pipelines, including 422 miles of large-diameter pipelines, the Natrium complex in Marshall County, West Virginia, with a cryogenic processing capacity of 400 MMcf/d and fractionation capacity of approximately 123,000 Bbls/d, 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.

Overland Pass Pipeline

We own and operate a 50 percent interest in OPPL. OPPL is capable of transporting 255 Mbbls/d and includes approximately 1,096 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. In 2013, a pipeline connection and capacity expansions were installed to accommodate volumes coming from the Bakken Shale in the Williston basin in North Dakota. Our equity NGL volumes from our two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term transportation agreement.

Delaware Basin Gas Gathering System

We own a non-operated 50 percent interest in the Delaware basin gas gathering system in the Permian region. The system is comprised of 403 miles of gathering pipeline, located in west Texas.

Utica East Ohio Midstream

We own a 62 percent interest in UEOM, a joint project to develop infrastructure for the gathering, processing and fractionation of natural gas and NGLs in the Utica Shale play in Eastern Ohio. We, along with other equity owners, operate the infrastructure complex which consists of natural gas gathering and compression facilities, four processing plants with a total capacity of 800 MMcf per day, 41 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 that are operated by our partner. These assets earn a fixed fee that escalates annually within a specified range.

Appalachia Midstream

Through our wholly owned subsidiary Appalachia Midstream, we operate 100 percent of and own an approximate average 45 percent interest in multiple natural gas gathering systems that consist of approximately 970 miles of gathering pipeline in the Marcellus Shale region. 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. Appalachia Midstream operates the assets under long-term, 100 percent fixed-fee gathering agreements that include significant acreage dedications and cost of service mechanisms.

Operating Statistics

The following table summarizes our significant operating statistics for Williams Partners’ midstream business:

	2015	2014	2013
Volumes: (1)			
Gathering (Tbtu)	3,298	2,482	1,731
Plant inlet natural gas (Tbtu)	1,448	1,419	1,549
NGL production (Mbbls/d) (2)	130	128	143
NGL equity sales (Mbbls/d) (2)	31	27	40
Crude oil transportation (Mbbls/d) (2)	126	105	117
Geismar ethylene sales (millions of pounds)	1,066	—	467

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

(2) Annual average Mbbls/d.

14

Williams NGL & Petchem Services

The Williams NGL & Petchem Services segment is comprised of our Texas Belle pipeline and certain other domestic olefins pipeline assets and certain Canadian growth projects under development, including a propane dehydrogenation facility and a liquids extraction plant. As this segment is currently comprised primarily of projects under development, reported revenues to-date are nominal.

Additional Business Segment Information

Our ongoing business segments are presented as continuing operations in the accompanying financial statements and Notes to Consolidated Financial Statements included in Part II.

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, distributions 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 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.

Revenues by service that exceeded 10 percent of consolidated revenue include:

	Total (Millions)
2015	
Service:	
Regulated natural gas transportation & storage	$1,938
Gathering, processing, and production handling	2,804
2014	
Service:	
Regulated natural gas transportation & storage	$1,781
Gathering, processing, and production handling	1,838
2013	
Service:	
Regulated natural gas transportation & storage	$1,704
Gathering, processing and production handling	966

We have one customer, Chesapeake Energy Corporation, and its affiliates, that accounts for 18 percent of our total revenue. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk for additional details.)

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 gas pipeline company 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 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. Each of our interstate natural gas pipeline companies establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are:

- 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, Williams Partners owns a 50 percent interest in and is 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.

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, and the Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011 (Pipeline Safety Act), which regulates 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. However, PHMSA is completing a congressionally-mandated review of the adequacy of the existing federal and state regulations for gathering lines and has indicated that it may apply additional safety standards to rural gas gathering lines in the future.

States are 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.

On January 3, 2012, the Pipeline Safety Act was enacted. The Pipeline Safety Act requires PHMSA to complete a number of reports in preparation for potential rulemakings. The issues addressed in these rulemaking provisions include, but are not limited to, the use of automatic or remotely controlled shut-off valves on new or replaced transmission line facilities, modifying the requirements for pipeline leak detection systems, and expanding the scope of the pipeline integrity management requirements for both gas and liquid pipeline systems. PHMSA is considering these and other provisions in the Pipeline Safety Act and has sought public comment on changes to the standards in its pipeline safety regulations.

Pipeline Integrity Regulations

We have developed 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 2016 associated with this program to be approximately $68 million. Management considers the 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 developed a 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 2016 associated with this program will be approximately $8 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 Regulation

Our onshore midstream gathering operations are subject to regulation by states in which we operate. Of the states where our midstream business gathers gas, currently only Texas and New York actively regulate gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. New York has specific regulations pertaining to the design, construction and operations of gathering lines in New York.

OCSLA

Our offshore midstream gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Although offshore gathering facilities are not subject to the NGA, offshore transmission pipelines are subject to the NGA, and in recent years the FERC has taken a broad view of offshore transmission, finding many shallow-water pipelines to be jurisdictional transmission. Most offshore gathering facilities are subject to the OCSLA, which provides in part that outer continental shelf pipelines “must provide open and nondiscriminatory access to both owner and nonowner shippers.”

Olefins

Our olefins assets are regulated by the Louisiana Department of Environmental Quality, the Texas Railroad Commission, and various other state and federal entities regarding our liquids pipelines.

These olefins assets are also subject to the liquid pipeline safety and integrity regulations previously discussed above since both Louisiana and Texas have adopted the integrity management regulations defined by PHMSA.

17

Canadian Operations

Our Canadian assets are regulated by the Alberta Energy Regulator (AER) and we also have certain facilities that are regulated by the Alberta Environment and Parks (AEP). The two agencies, AER and AEP, include specifics to pipeline safety and integrity. The regulatory system for the Alberta oil and gas industry incorporates a large measure of self-regulation, providing that licensed operators are held responsible for ensuring that their operations are conducted in accordance with all provincial regulatory requirements. For situations in which noncompliance with the applicable regulations is at issue, the AER has an enforcement process with escalating consequences.

See Note 18 – Contingent Liabilities and Commitments of our Notes to Consolidated Financial Statements for further details on our regulatory matters. For additional information regarding regulatory matters, please also refer to “Risk Factors — The operation of our businesses might also be adversely affected by 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,” “- Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects;" 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 “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 current expectations,” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Environmental” and “Environmental Matters” in Note 18 – Contingent Liabilities and Commitments of our Notes to Consolidated Financial Statements.

COMPETITION

Gas Pipeline Business

The natural gas industry has a highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity. Large reserves of shale gas have been discovered, in many cases much closer to major market centers. As a result, pipeline capacity is being used more efficiently and competition among pipeline suppliers to connect growing supply to market has increased.

States have developed new plans that require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This has lowered the growth of residential gas demand. However, due to relatively low prices of natural gas, demand for electric power generation has increased.

Local distribution company (LDC) and electric industry restructuring by states have affected pipeline markets. Pipeline operators are increasingly challenged to accommodate the flexibility demanded by customers and allowed under tariffs. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity. In addition, LDCs are entering the long haul transportation business through joint venture pipelines.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity from traditional producing areas. Future utilization of pipeline capacity will depend on these factors and others impacting both U.S. and global demand for natural gas.

Midstream Business

Generally, our gathering and processing agreements are long-term agreements that may include acreage dedication. We primarily face competition to the extent these agreements approach renewal or new volume opportunities arise. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. Our gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. We primarily compete with five to ten companies across all basins in which we provide services.

Ethylene and propylene markets, and therefore our olefins business, compete in a worldwide marketplace. At Geismar, we currently benefit from the lower cost natural gas based feedstocks in North America versus other crude based feedstocks worldwide. The majority of North American olefins producers have significant downstream petrochemical manufacturing for plastics and other products. As such, they buy or sell ethylene and propylene as required. We operate as a merchant seller of olefins with no downstream manufacturing, and therefore can be either a supplier or a competitor at any given time to these other companies. We compete on the basis of service, price and availability of the products we produce.

Our Canadian midstream facilities continue to be the only NGL/olefins fractionator in western Canada and the only processor of oil sands upgrader offgas. Our extraction of liquids from the upgrader offgas stream allows the upgraders to burn cleaner natural gas streams and reduce their overall air emissions. Our Canadian midstream business competes for the sale of its products with traditional Canadian midstream companies on the basis of operational expertise, price, service offerings and availability of the products we produce. The sales of our NGL and olefin products compete in the worldwide marketplace.

For additional information regarding competition for our services or otherwise affecting our business, please refer to “Risk Factors - The long-term 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 our traditional markets, “-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, 2016, we had approximately 6,578 full-time employees.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 19 – Segment Disclosures of our Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also see Note 19 – Segment Disclosures of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

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

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

- The status, expected timing and expected outcome of the proposed ETC Merger;
- Statements regarding the proposed ETC Merger;
- Our beliefs relating to value creation as a result of the proposed ETC Merger;
- Benefits and synergies of the proposed ETC Merger;
- Future opportunities for the combined company;
- Other statements regarding Williams’ and Energy Transfer’s future beliefs, expectations, plans, intentions, financial condition or performance;
- Expected levels of cash distributions by Williams Partners L.P. (WPZ) with respect to general partner interests, incentive distribution rights and limited partner interests;
- Levels of dividends to Williams stockholders;
- Future credit ratings of Williams and WPZ;
- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Cash flow from operations or results of operations;
- Seasonality of certain business components;

- Natural gas, natural gas liquids, and olefins 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:

- Satisfaction of the conditions to the completion of the proposed ETC Merger, including receipt of the approval of Williams' stockholders;
- The timing and likelihood of completion of the proposed ETC Merger, including the timing, receipt and terms and conditions of any required governmental and regulatory approvals for the proposed merger that could reduce anticipated benefits or cause the parties to abandon the proposed transaction;
- The possibility that the expected synergies and value creation from the proposed ETC Merger will not be realized or will not be realized within the expected time period;
- The risk that the businesses of Williams and Energy Transfer will not be integrated successfully;
- Disruption from the proposed ETC Merger making it more difficult to maintain business and operational relationships;
- The risk that unexpected costs will be incurred in connection with the proposed ETC Merger;
- The possibility that the proposed ETC Merger does not close, including due to the failure to satisfy the closing conditions;
- Whether WPZ will produce sufficient cash flows to provide the level of cash distributions we expect;
- Whether Williams is able to pay current and expected levels of dividends;
- Availability of supplies, market demand and volatility of prices;
- Inflation, interest rates, fluctuation in foreign exchange 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 execute investment opportunities;
- Our ability to acquire new businesses and assets and successfully integrate those operations and assets into our existing businesses as well as successfully expand our facilities;
- Development of alternative energy sources;
- The impact of operational and developmental hazards and unforeseen interruptions;
- Costs of, changes in, or the results of laws, government regulations (including safety and environmental regulations), environmental liabilities, litigation, and rate proceedings;
- Williams' costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;

- 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;
- Acts of terrorism, including cybersecurity threats and related disruptions;
- Additional risks described in our filings with the SEC.

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

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

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. 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, operating results, and financial condition, as well as adversely affect the value of an investment in our securities.

The pendency of the proposed ETC Merger could adversely affect our business and operations.

In connection with the proposed ETC Merger, some of our customers or vendors may delay or defer decisions, which could negatively impact our revenues, earnings, cash flows and expenses, regardless of whether the proposed ETC Merger is completed. Similarly, our current and prospective employees may experience uncertainty about their future roles following the proposed ETC Merger, which may materially adversely affect our ability to attract and retain key personnel during the pendency of the proposed ETC Merger. If we fail to complete the proposed ETC Merger, it may be difficult and expensive to recruit and hire replacements for departed employees. The proposed ETC Merger, its effects and related matters may also distract our employees from day-to-day operations and require substantial commitments of time and resources. In addition, due to operating covenants in the Merger Agreement, we may be unable, during the pendency of the proposed ETC Merger, to pursue certain strategic transactions, undertake certain significant capital projects, undertake certain significant financing transactions and otherwise pursue other actions that are not in the ordinary course of business. Such risks relating to vendors, customers, employees and those risks arising from operating covenants in the Merger Agreement will also apply to varying degrees to our subsidiaries and affiliates and thereby have a corresponding impact on us.

There can be no assurance when or even if the proposed ETC Merger will be completed.

Completion of the proposed ETC Merger is subject to the satisfaction or waiver of a number of conditions that must be satisfied or waived, including approval of the proposed ETC Merger by our stockholders, the expiration or termination of the waiting period applicable to the proposed ETC Merger under antitrust laws, the absence of any law or order prohibiting the closing of the proposed ETC Merger, the declaration by the SEC of the effectiveness of the registration statement on Form S-4 of which the proxy statement/prospectus forms a part and the authorization of the listing on the NYSE of the ETC common shares. There can be no assurance that we, ETC, and Energy Transfer will be able to satisfy the closing conditions or that closing conditions beyond their or our control will be satisfied or waived. Completion of the proposed ETC Merger is also conditioned on the accuracy of representations and warranties made by the parties to the Merger Agreement (subject to customary materiality qualifiers and other customary exceptions) and the performance in all material respects by the parties of obligations imposed under the Merger Agreement.We and Energy Transfer can mutually agree at any time to terminate the Merger Agreement, even if our stockholders have already voted to approve the Merger Agreement. We and Energy Transfer can also terminate the Merger Agreement under other specified circumstances.

If the proposed ETC Merger is not completed, we will be subject to a number of risks, including the following:

- Because the current price of shares of our common stock may reflect a market premium based on the assumption that we will complete the proposed ETC Merger, a failure to complete the proposed ETC Merger could result in a decline in the price of shares of our common stock;
- In specified circumstances, we may be required to pay Energy Transfer a termination fee of $1.48 billion and certain of their expenses;
- We will not realize the benefits expected from being part of a larger combined organization;
- We have incurred and expect to continue incurring a number of non-recurring ETC Merger-related expenses that must be paid even if the proposed ETC Merger is not completed.

In addition, if the proposed ETC Merger is not completed, we may experience negative reactions from the financial markets and from our customers and employees. We also could be subject to litigation related to any failure to complete the proposed ETC Merger or to proceedings commenced against us to attempt to force us to perform our obligations under the Merger Agreement.

The Merger Agreement contains provisions that could discourage a potential competing acquirer of us or could result in any competing proposal being at a lower price than it might otherwise be.

The Merger Agreement contains provisions that, subject to certain exceptions, restrict our ability to solicit, encourage, facilitate or discuss competing third-party proposals to acquire all or a significant part of us. In addition, Energy Transfer will have an opportunity to negotiate with us in response to any competing proposal that may be made before our board of directors is permitted to withdraw or qualify its recommendation. In some circumstances, upon termination of the Merger Agreement, we may be required to pay to Energy Transfer a termination fee of $1.48 billion.

These provisions could discourage a potential competing acquirer that might have an interest in acquiring all or a significant part of us from considering or proposing that acquisition, even if it were prepared to pay consideration with a higher value than the consideration proposed to be received or realized in the proposed ETC Merger, or might result in a potential competing acquirer proposing to pay a lower price than it might otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances.

The integration of our business following the proposed ETC Merger will involve considerable risks and may not be successful.

Achieving the anticipated benefits of the proposed ETC Merger will depend in part upon whether Energy Transfer can integrate our businesses in an effective and efficient manner. Energy Transfer may not be able to accomplish this integration process successfully. The integration of any business may be complex and time-consuming. The difficulties that could be encountered include the following:

- Integrating personnel, operations and systems;
- Coordinating the geographically dispersed organizations;

•Distraction of management and employees from operations changes in corporate culture;
•Retaining existing customers and attracting new customers;
•Maintaining business relationships; and
•Inefficiencies associated with the integration of the operations of ETC.

In addition, there will be integration costs and non-recurring transaction costs associated with the proposed ETC Merger (such as fees paid to legal, financial, accounting and other advisors and other fees paid in connection with the proposed ETC Merger) and achieving the expected cost savings and synergies associated therewith, and such costs may be significant.

An inability to realize the full extent of the anticipated benefits of the proposed ETC Merger, as well as any delays encountered in the integration process and the realization of such benefits, could have an adverse effect upon the revenues, level of expenses and operating results of Energy Transfer, which may adversely affect the value of Energy Transfer common units and, in turn, the value of ETC common shares after the completion of the merger.

Stockholder litigation could prevent or delay the closing of the proposed ETC Merger or otherwise negatively impact our business and operations.

We have incurred and may continue to incur additional costs in connection with the defense or settlement of the currently pending and any future stockholder litigation in connection with the proposed ETC Merger. Such litigation may adversely affect our ability to complete the proposed ETC Merger and could also have an adverse effect on our financial condition and results of operations.

We are exposed to the credit risk of our customers and counterparties, including Chesapeake Energy Corporation and its affiliates, 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 will not 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. The current low commodity price environment has, in particular, negatively impacted natural gas producers 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, results of operations, cash flows and financial conditions. For example, Chesapeake Energy Corporation and its affiliates, which accounted for approximately 18 percent of our 2015 consolidated revenues, have experienced significant, negative financial results due to sustained low commodity prices. 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, results of operations, cash flows and financial condition.

Prices for NGLs, olefins, natural gas, 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 NGLs, olefins, natural gas, oil or other commodities, and the differences between prices of these commodities, and could be materially adversely affected by an extended period of current low commodity prices or a further 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 NGLs, olefins, natural gas, 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, olefins, 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 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.

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.
Our credit ratings have recently been downgraded. 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 sub investment-grade credit ratings by each of the three ratings agencies.
Our ability to obtain credit in the future could be affected by WPZ’s credit ratings.
A substantial portion of our operations are conducted through, and our cash flows are substantially derived from distributions paid to us by, WPZ. Due to our relationship with WPZ, our ability to obtain credit will be affected by WPZ’s credit ratings. WPZ’s credit ratings have recently been downgraded. If WPZ were to experience a further deterioration in its credit standing or financial condition, our access to capital and our ratings could be further adversely affected. Any future downgrading of a WPZ credit rating could also result in a further downgrading of our credit rating. A downgrading of a WPZ credit rating could limit our ability to obtain financing in the future upon favorable terms, if at all.

The long-term 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 our traditional markets.

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 and NGL 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. 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 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 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 may not be available on terms and conditions we find acceptable or, where multiple parties are trying to acquire an acquisition candidate, 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, fractionation or storage facilities or olefins processing facilities, as well as the expansion of existing facilities. We also face all the risks associated with construction. These risks include the inability to obtain skilled labor, equipment, materials, permits, rights-of-way and other required inputs in a timely manner such that projects are completed on time 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 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 results of operations, including the possible impairment of our assets, and could also have an adverse impact on our financial position or cash flows.

We do not own all of the interests in the Partially Owned Entities, which could adversely affect our ability to operate and control these assets in a manner beneficial to us.

Because we do not control the Partially Owned Entities, we may have limited flexibility to control the operation of or cash distributions received from these entities. The Partially Owned Entities' organizational documents generally require distribution of their available cash to their members on a quarterly basis; however, in each case, available cash is reduced, in part, by reserves appropriate for operating the businesses. As of December 31, 2015, our investments in the Partially Owned Entities accounted for approximately 8 percent of our total consolidated assets. Conflicts of interest may arise in the future between us, on the one hand, and our Partially Owned Entities, on the other hand, with regard to our Partially Owned Entities' governance, business and operations. If a conflict of interest arises between us and a Partially Owned Entity, other owners may control the Partially Owned Entity's actions with respect to such matter (subject to certain limitations), which could be detrimental to our business. Any future disagreements with the other co-owners of these assets could adversely affect our ability to respond to changing economic or industry conditions, which could have a material adverse effect on our business, financial condition, results of operations and 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 WPZ and our other 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 cash flow depends heavily on the earnings and distributions of WPZ.

Our partnership interest, including the general partner's holding of incentive distribution rights in WPZ, is currently our largest cash-generating asset. Therefore, we are, at the least, indirectly exposed to all the risks to which WPZ is subject and our cash flow is heavily dependent upon the ability of WPZ to make distributions to its partners. A significant decline in WPZ's earnings and/or distributions would have a corresponding negative impact on us.

We may not be able to sell assets or, if we are able to sell assets, to raise a sufficient amount of capital from such asset sales. In addition, the timing to enter into and close any asset sales could be significantly different than our expected timeline.

In addition to the recent announcement that WPZ plans to monetize assets during 2016 to fund capital and investment expenditures, it is possible that we could also engage in asset sales. Given the commodity markets, financial markets and other challenges currently facing the energy sector, our competitors may also engage in asset sales leading to lower demand for the assets we wish to sell. We may not be able to sell the assets we identify for sale on favorable terms or at all. If we are able to sell assets, the timing of the receipt of the asset sale proceeds may not align with the timing of our capital requirements. A failure to raise sufficient capital from asset sales or a misalignment of the timing of capital raised and capital funding needs could have an adverse impact on our business, financial condition, results of operations and cash flows.

An impairment of our assets, including goodwill, 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. If the current depressed energy commodity price environment persists for a prolonged period or further declines, such circumstances could result in additional impairments of our assets beyond those incurred in 2015 including impairments of our goodwill, property, plant and equipment, intangible assets, and/or equity method investments. Additionally any asset monetization could result in impairments if any assets are sold 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 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. Some of our competitors are large oil, natural gas and petrochemical companies that have greater access to supplies of natural gas and NGLs than we do. 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. Similarly, a highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity, have developed. As a result, pipeline capacity is being used more efficiently, and peaking and storage services are increasingly effective substitutes for annual pipeline capacity. 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 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 fuel sources, such as electricity, coal, fuel oils, or nuclear energy;
- Natural gas, NGL, and olefins 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.

Some of our businesses, including WPZ's Central business, 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. For instance, pursuant to a compression services agreement, WPZ's Central business receives a substantial portion of its compression capacity on certain gathering systems from EXLP Operating LLC ("Exterran Operating"). Exterran Operating has, until December 31, 2020, the exclusive right to provide WPZ's Central business with compression services on certain gas gathering systems located in Wyoming, Texas, Oklahoma, Louisiana, and Arkansas, in return for the payment of specified monthly rates for the services provided, subject to an annual escalation provision. 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.

We will conduct certain operations through joint ventures that may limit our operational flexibility or require us to make additional capital contributions.

Some of our operations are conducted through joint venture arrangements, and we may enter additional joint ventures in the future. In a joint venture arrangement, we have less operational flexibility, as actions must be taken in accordance with the applicable governing provisions of the joint venture. In certain cases we:

- Have limited ability to influence or control certain day to day activities affecting the operations;
- Cannot control the amount of capital expenditures that we are required to fund with respect to these operations;
- Are dependent on third parties to fund their required share of capital expenditures;
- May be subject to restrictions or limitations on our ability to sell or transfer our interests in the jointly owned assets;
- May be forced to offer rights of participation to other joint venture participants in the area of mutual interest.

In addition, joint venture participants may have obligations that are important to the success of the joint venture, such as the obligation to pay substantial carried costs pertaining to the joint venture and to pay their share of capital and other costs of the joint venture. The performance and ability of third parties to satisfy their obligations under joint venture arrangements is outside our control. If these third parties do not satisfy their obligations under these arrangements, our business may be adversely affected. Joint venture partners may be in a position to take actions contrary to instructions or requests or contrary to our policies or objectives, and disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

If we fail to make a required capital contribution under the applicable governing provisions of a joint venture arrangements, we could be deemed to be in default under the joint venture agreement. Joint venture partners may be permitted to fund any deficiency resulting from our failure to make such capital contribution, which would result in a dilution of our ownership interest, or such joint venture partners may have the option to purchase all of our existing interest in the subject joint venture.

The risks described above or the failure to continue joint ventures, or to resolve disagreements with joint venture partners could adversely affect our ability to conduct our operation that is the subject of a joint venture, which could in turn negatively affect our financial condition and results of operations.

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, the processing of olefins, 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, olefins products, brine or industrial chemicals;
- 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;
- Truck and rail loading and unloading;
- 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. We currently maintain excess liability insurance with limits of $820 million per occurrence and in the annual aggregate with a $2 million per occurrence deductible. This insurance covers us, our subsidiaries, and certain of our affiliates for legal and contractual liabilities arising out of bodily injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability for full limits, with the first $135 million of insurance also providing gradual pollution liability coverage for natural gas and NGL operations.

Although we maintain property insurance on certain physical assets that we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets or the entire amount of business interruption loss we may experience. In addition, certain perils may be excluded from coverage or be sub-limited. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. We may elect to self-insure a portion of our risks. We do not insure our onshore underground pipelines for physical damage, except at certain locations such as river crossings and compressor stations. Offshore assets are covered for property damage when loss is due to a named windstorm event, but coverage for loss caused by a named windstorm is significantly sub-limited and subject to a large deductible. All of our insurance is subject to deductibles.

In addition, to the insurance coverage described above, we are a member of Oil Insurance Limited (“OIL”), an energy industry mutual insurance company, which provides coverage for damage to our property. As an insured member of OIL, we share in the losses among other OIL members even if our property is not damaged.

The occurrence of any risks not fully covered by insurance could have a material adverse effect on our business, results of operations, financial condition, 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.

Acts of terrorism could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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.

Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.

We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. While we believe that we maintain appropriate information security policies, practices and protocols, we face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational industrial control systems and safety systems that operate our pipelines, plants and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, "hacktivists," or private individuals. 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. We could 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. 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 our assets, unnecessary waste, safety incidents, damage to the environment, reputational damage, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.

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, under the Natural Gas Act of 1938, 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;
- 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.

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 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 chemical and 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, processing of olefins, 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 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 (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) 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.

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

33

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, results of operations, financial condition and cash flows.

The operation of our businesses might also be adversely affected by 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 might be revised or reinterpreted, and new laws and regulations, including those pertaining to oil and gas hedging and cash collateral requirements, might 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 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 and our results of operations could be adversely affected.

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.

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 term. 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, results of operations, financial condition and cash flows.

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 manners 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, 2015, was $23.99 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, please read Note 14 – Debt, Banking Arrangements, and Leases.
Institutional knowledge residing with current employees nearing retirement eligibility or with our former employees might not be adequately preserved.
We expect that a significant percentage of employees will become eligible for retirement over the next several years. In certain areas of our business, institutional knowledge resides with employees who have many years of service. As these employees reach retirement age or their services are no longer available to us, we may not be able to replace them with employees of comparable knowledge and experience. In addition, we may not be able to retain or recruit other qualified individuals, and our efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to us.
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.
One of our subsidiaries acts as the general partner of a publicly traded limited partnership, Williams Partners L.P. As such, this subsidiary’s operations may involve a greater risk of liability than ordinary business operations.
One of our subsidiaries acts as the general partner of WPZ, a publicly traded limited partnership. This subsidiary may be deemed to have undertaken contractual obligations with respect to WPZ as the general partner and to the limited partners of WPZ. Activities determined to involve such obligations to other persons or entities typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interest is found to exist. Our control of the general partner of WPZ may increase the possibility of claims of breach of such duties, including claims brought due to conflicts of interest (including conflicts of interest that may arise between WPZ, on the one hand, and its general partner and that general partner’s affiliates, including us, on the other hand). Any liability resulting from such claims could be material.
Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.
We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic, political and legal conditions and regulatory environment in the countries in which we have interests or in which we might pursue acquisition or investment opportunities present risks that are different from or greater than those in the United States. These risks include, among others, delays in construction and interruption of business, as well as risks of renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, including with respect to the prices we realize for the commodities we produce and sell. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments

36

could make it more difficult to obtain nonrecourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments.
Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.
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, results of operations and financial condition.
The execution of the integration strategy following WPZ’s merger with Access Midstream Partners, L.P. (“ACMP”) in February 2015 (the “ACMP Merger”) may not be successful.
The ultimate success of the ACMP Merger will depend, in part, on the ability of the combined company to realize the anticipated benefits from combining these formerly separate businesses. Realizing the benefits of the ACMP Merger will depend in part on the effective integration of assets, operations, functions and personnel while maintaining adequate focus on our core businesses. Any expected cost savings, economies of scale, enhanced liquidity or other operational efficiencies, as well as revenue enhancement opportunities, or other synergies, may not occur.
If management is unable to minimize the potential disruption of our ongoing business and the distraction of management during the integration process, the anticipated benefits of the ACMP Merger may not be realized or may only be realized to a lesser extent than expected. In addition, the inability to successfully manage the integration could have an adverse effect on us.
The integration process could result in the loss of key employees, as well as the disruption of each of our ongoing businesses or the creation of inconsistencies in standards, controls, procedures and policies. Any or all of those occurrences could adversely affect our businesses’ ability to maintain relationships with service providers, customers and employees or to achieve the anticipated benefits of the ACMP Merger. Integration may also result in additional and unforeseen expenses, which could reduce the anticipated benefits of the ACMP Merger and materially and adversely affect our business, operating results and financial condition.
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 post-retirement 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.
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 an IRS 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 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.

The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements that we did not assume in our agreements with WPX.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. A court could deem the spin-off or certain internal restructuring transactions undertaken by us in connection with the separation to be a fraudulent conveyance or transfer. Fraudulent conveyances or transfers are defined to include transfers made or obligations incurred with the actual intent to hinder, delay or defraud current or future creditors or transfers made or obligations incurred for less than reasonably equivalent value when the debtor was insolvent, or that rendered the debtor insolvent, inadequately capitalized or unable to pay its debts as they become due. A court could void the transactions or impose substantial liabilities upon us, which could adversely affect our financial condition and our results of operations. Whether a transaction is a fraudulent conveyance or transfer will vary depending upon the jurisdiction whose law is being applied. Under the separation and distribution agreement between us and WPX, from and after the spin-off, each of WPX and we are responsible for the debts, liabilities and other obligations related to the business or businesses which each owns and operates. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to WPX, particularly if WPX were to refuse or were unable to pay or perform the subject allocated obligations.

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 further 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 cash distributions and implied distribution yield. The distribution 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.

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.

In November 2013, we became aware of deficiencies with the air permit for the Fort Beeler gas processing facility located in West Virginia. We notified the EPA and the West Virginia Department of Environmental Protection and are working to bring the Fort Beeler facility into full compliance. At December 31, 2015, we have accrued liabilities of $140,000 for potential penalties arising out of the deficiencies.

On January 21, 2016, we received a Compliance Order from the Pennsylvania Department of Environmental Protection requiring the correction of several alleged deficiencies arising out of the construction of the Springville Gathering Line, the Pennsylvania Mainline Gathering Line, and the 2008 Core Zone Gathering Line. The Order also identifies civil penalties in the amount of approximately $712,000. We are currently evaluating the Order and our response.

Other

The additional information called for by this item is provided in Note 18 – Contingent Liabilities and Commitments of the 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, age, period of service, and title of each of our executive officers as of February 26, 2016, are listed below. As previously discussed, 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.

Alan S. Armstrong	Director, Chief Executive Officer, and President Age: 53 Position held since 2011. From 2002 to 2011, Mr. Armstrong served as Senior Vice President - Midstream and acted as President of our midstream business. From 1999 to 2002, Mr. Armstrong was Vice President, Gathering and Processing in our midstream business and from 1998 to 1999 was Vice President, Commercial Development. Mr. Armstrong has served as a director of the general partner of ACMP/WPZ since 2012, as Chief Executive Officer since December 31, 2014, and as Chairman of the Board since February 2, 2015. Mr. Armstrong has served as a director of BOK Financial Corporation, a financial services company, since 2013. Mr. Armstrong also served as Chairman of the Board and Chief Executive Officer of the general partner of Pre-merger WPZ from 2011 until the ACMP Merger, as Senior Vice President - Midstream from 2010 to 2011, and director and Chief Operating Officer from 2005 to 2010.
Walter J. Bennett	Senior Vice President — West Age: 46 Position held since January 2015. Mr. Bennett was formerly Chief Operating Officer of Chesapeake Midstream Development and served as Senior Vice President-Operations at Boardwalk Pipeline Partners. Previously, Mr. Bennett served in a variety of senior positions at Gulf South Pipeline Company that included operations and commercial responsibilities. Mr. Bennett began his career at a subsidiary of Koch Industries. Mr. Bennett has served as Senior Vice President - West of the general partner of ACMP/WPZ since December 2013 and served as Senior Vice President - West of the general partner of Pre-merger WPZ from January 2015 until the ACMP Merger.

Francis (Frank) E. Billings	Senior Vice President — Corporate Strategic Development Age: 53 Position held since January 2014. Mr. Billings served as Senior Vice President - Northeast G&P of us and Pre-merger WPZ from January 2013 to January 2014. Mr. Billings served as Vice President of our midstream gathering and processing business from 2011 until 2013 and as Vice President, Business Development from 2010 to 2011. Mr. Billings served as President of Cumberland Plateau Pipeline Company, a privately held company developing an ethane pipeline to serve the Marcellus Shale area, from 2009 until 2010. From 2008 to 2009, Mr. Billings served as Senior Vice President of Commercial for Crosstex Energy, Inc. and Crosstex Energy L.P., an independent midstream energy services master limited partnership and its parent corporation. In 1988, Mr. Billings joined MAPCO Inc., which merged with one of our subsidiaries in 1998, serving in various management roles, including in 2008 as a Vice President in the midstream business. Mr. Billings served as Senior Vice President - Corporate Strategic Development of the general partner of Pre-merger WPZ from January 2014 until the ACMP Merger. He has served as a director of the general partner of ACMP/WPZ since February 2014 and as Senior Vice President - Corporate Strategic Development since the ACMP Merger.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 64 Position held since 2003. Prior to joining us, Mr. Chappel held various financial, administrative and operational leadership positions. Mr. Chappel has served as a director of the general partner of ACMP/WPZ since 2012 and as Chief Financial Officer of the general partner of ACMP/WPZ since December 31, 2014. Mr. Chappel has also served as a member of the Management Committee of Northwest Pipeline since 2007. Mr. Chappel served as Chief Financial Officer and a director of the general partner of Pre-merger WPZ from 2005 until the ACMP Merger. Mr. Chappel was Chief Financial Officer from 2007 and a director from 2008 of the general partner of Williams Pipeline Partners L.P. (WMZ), until its merger with Pre-merger WPZ in 2010. Mr. Chappel is a director of SUPERVALU, Inc. (a grocery and pharmacy company).
John R. Dearborn	Senior Vice President — NGL & Petchem Services Age: 58 Position held since 2013. Mr. Dearborn served as a senior leader for Saudi Basic Industries Corporation, a petrochemical company, from 2011 to 2013. From 2001 to 2011, Mr. Dearborn served in a variety of leadership positions with the Dow Chemical Company. Mr. Dearborn also worked for Union Carbide Corporation, prior to its merger with DOW, from 1981 to 2001 where he served in several leadership roles. Mr. Dearborn also served as Senior Vice President - NGL & Petchem Services of the general partner of Pre-merger WPZ from 2013 until the ACMP Merger and has served in that role for the general partner of ACMP/WPZ since the ACMP Merger.

Robyn L. Ewing	Senior Vice President and Chief Administrative Officer Age: 60 Position held since 2008. From 2004 to 2008, Ms. Ewing was Vice President of Human Resources. Prior to joining Williams, Ms. Ewing worked at MAPCO, which merged with Williams in 1998. Ms. Ewing began her career with Cities Service Company in 1976.
Rory L. Miller	Senior Vice President — Atlantic - Gulf Age: 55 Position held since 2013. From 2011 until 2013, Mr. Miller was Senior Vice President - Midstream of Williams and the general partner of Pre-merger WPZ, acting as President of Williams' midstream business. Mr. Miller was a Vice President of Williams' midstream business from 2004 until 2011. Mr. Miller served as a director and Senior Vice-President - Atlantic-Gulf of the general partner of Pre-merger WPZ from 2011 until the ACMP Merger and has served in those roles for the general partner of ACMP/WPZ since the ACMP Merger. Mr. Miller has also served as a member of the Management Committee of Transco, since 2013.
Sarah C. Miller	Senior Vice President, General Counsel, and Secretary Age: 44 Position held since 2015. Ms. Miller joined Williams in 2000, where she has served in a variety of legal leadership positions, including Vice President, Corporate Secretary and Assistant General Counsel for the company's corporate secretary team, Senior Counsel for the company's midstream business, and as Senior Attorney for the legal department's business development team. She was named Senior Vice President and General Counsel on June 20, 2015. Prior to joining Williams, Ms. Miller was a litigation associate at Crowe & Dunlevy.
Fred E. Pace	Senior Vice President — E&C (Engineering and Construction) Age: 54 Position held since 2013. From 2011 until 2013, Mr. Pace served Williams in project engineering and development roles, including service as Vice President Engineering and Construction for our midstream business. From 2009 to 2011, Mr. Pace was the managing member of PACE Consulting, LLC, an engineering and consulting firm serving the energy industry. In 2003, Mr. Pace co-founded Clear Creek Natural Gas, LLC, later known as Clear Creek Energy Services, LLC, a provider of engineering, construction, and operational services to the energy industry where he served as Chief Executive Officer until 2009. Mr. Pace has over 30 years of experience in the engineering, construction, operation, and project management areas of the energy industry, including prior service with Williams from 1985 to 1990. Mr. Pace also served as Senior Vice President - E&C of the general partner of Pre-merger WPZ from 2013 until the ACMP Merger and has served in that role for the general partner of Pre-merger WPZ since the ACMP Merger.

Brian L. Perilloux	Senior Vice President — Operational Excellence Age: 54 Position held since 2013. Mr. Perilloux served as a Vice President of our midstream business from 2011 until 2013. From 2007 to 2011, Mr. Perilloux served in various roles in our midstream business, including engineering and construction roles. Prior to joining Williams, Mr. Perilloux was an officer of a private international engineering and construction company. Mr. Perilloux served as Senior Vice President - Operational Excellence of the general partner of Pre-merger WPZ from 2013 until the ACMP Merger and has served in that role for the general partner of ACMP/WPZ since the ACMP Merger.
Robert S. Purgason	Senior Vice President — Central Age: 59 Position held since January 2015. Mr. Purgason has served as a director of the general partner of ACMP/WPZ since 2012 and as Senior Vice President-Access of the general partner of ACMP/WPZ since the ACMP Merger. Mr. Purgason served as Chief Operating Officer of the general partner of ACMP/WPZ from 2010 until the ACMP Merger. Prior to joining the general partner of ACMP/WPZ, Mr. Purgason spent five years at Crosstex Energy Services, L.P. and was promoted to Senior Vice President - Chief Operating Officer in 2006. Prior to Crosstex, Mr. Purgason spent 19 years with us in various senior business development and operational roles. Mr. Purgason began his career at Perry Gas Companies in Odessa, Texas working in all facets of the natural gas treating business. Mr. Purgason has also served on the Board of Directors of L.B. Foster Company (a manufacturer, fabricator, and distributor of products and services for the rail, construction, energy, and utility markets) since December 2014.
James E. Scheel	Senior Vice President — Northeast G&P Age: 51 Position held since January 2014. From 2012 to 2014, Mr. Scheel served as Senior Vice President - Corporate Strategic Development of us and the general partner of Pre-merger WPZ. From 2011 until 2012, Mr. Scheel served as Vice President of Business Development for our midstream business. Mr. Scheel joined Williams in 1988 and has served in leadership roles in business strategic development, engineering and operations, our NGL business, and international operations. Mr. Scheel has served as a director and Senior Vice President - Northeast G&P of the general partner of ACMP/WPZ since the ACMP Merger, having previously served as a director of the general partner of ACMP/WPZ from 2012 to February 2014. Mr. Scheel served as a director of the general partner of Pre-merger WPZ from 2012 until the ACMP Merger.

John D. Seldenrust	Senior Vice President — E&C (Engineering & Construction) Age: 51 Position held since July 2015. Mr. Seldenrust served as Senior Vice President - Eastern Operations for us from January 2015 to July 2015, and for ACMP/WPZ from 2013 to July 2015. Mr. Seldenrust also previously served in a variety of operations and engineering leadership roles at ACMP and Chesapeake Energy from 2004 to August 2013. Prior to joining Chesapeake, Mr. Seldenrust held reservoir, production and facilities engineering positions with ARCO Oil & Gas, Vastar Resources and BP America.
Ted T. Timmermans	Vice President, Controller, and Chief Accounting Officer Age: 59 Position held since 2005. Mr. Timmermans served as Assistant Controller of Williams from 1998 to 2005. Mr. Timmermans served as Vice President, Controller & Chief Accounting Officer of the general partner of Pre-merger WPZ until the ACMP Merger and has served in those roles for the general partner of ACMP/WPZ since the ACMP Merger. Mr. Timmermans served as Chief Accounting Officer of the general partner of WMZ from 2008 until its merger with Pre-merger WPZ in 2010.

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 16, 2016, we had approximately 7,754 holders of record of our common stock. The high and low sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	High	Low	Dividend
2015			
First Quarter	$51.15	$40.07	$0.58
Second Quarter	61.38	46.28	0.59
Third Quarter	58.77	34.64	0.64
Fourth Quarter	44.51	20.95	0.64
2014			
First Quarter	$42.94	$37.77	$0.4025
Second Quarter	59.68	39.31	0.425
Third Quarter	59.77	54.28	0.56
Fourth Quarter	57.00	41.21	0.57

Some of our subsidiaries’ borrowing arrangements may limit the transfer of funds to us. These terms have not impeded, nor are they expected to impede, our ability to pay dividends.

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 U.S. Pipeline Index for the period of five fiscal years commencing January 1, 2011. The Bloomberg U.S. Pipeline Index is composed of Columbia Pipeline Group, Inc., Enbridge, Inc., Inter Pipeline Ltd., Kinder Morgan, Inc., ONEOK, Inc., Pembina Pipeline Corp, Plains GP Holdings LP, Spectra Energy Corp, TransCanada Corp., and Williams. The graph below assumes an investment of $100 at the beginning of the period.

	2010	2011	2012	2013	2014	2015
The Williams Companies, Inc.	100.0	137.1	172.9	211.9	256.9	156.6
S&P 500 Index	100.0	102.1	118.4	156.6	178.0	180.5
Bloomberg U.S. Pipelines Index	100.0	137.9	156.4	173.6	203.1	112.3

Item 6. Selected Financial Data

The following financial data at December 31, 2015 and 2014, and for each of the three years in the period ended December 31, 2015, 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.

	2015	2014	2013	2012	2011
	(Millions, except per-share amounts)				
Revenues (1)	$7,360	$7,637	$6,860	$7,486	$7,930
Income (loss) from continuing operations (2)	(1,314)	2,335	679	929	1,078
Amounts attributable to The Williams Companies, Inc.:					
Income (loss) from continuing operations (2)	(571)	2,110	441	723	803
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations (2)	(.76)	2.91	.64	1.15	1.34
Total assets at December 31 (3) (4) (6)	49,020	50,455	27,065	24,248	16,432
Commercial paper and long-term debt due within one year at December 31 (5)	675	802	226	1	352
Long-term debt at December 31 (3) (4) (6)	23,812	20,780	11,276	10,656	8,300
Stockholders' equity at December 31 (3) (4)	6,148	8,777	4,864	4,752	1,296
Cash dividends declared per common share	2.450	1.958	1.438	1.196	.78

---

(1) Revenues for 2014 increased reflecting the consolidation of ACMP beginning in third quarter and new Canadian construction management services.

(2) Income (loss) from continuing operations:

- 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 pretax 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 pretax 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 pretax acquisition, merger, and transition expenses related to our acquisition of ACMP;
- For 2013 includes $99 million of deferred income tax expense incurred on undistributed earnings of our foreign operations that are no longer considered permanently reinvested;
- For 2011 includes $271 million of pretax early debt retirement costs.

(3) The increases in 2014 reflect assets acquired and debt assumed primarily related to our acquisition of ACMP (see Note 2 – Acquisitions) in third quarter as well as $1.9 billion of related debt issuances and $2.8 billion of debt issuances at WPZ. Additionally, we issued $3.4 billion of equity (see Note 14 – Debt, Banking Arrangements, and Leases and Note 15 – Stockholders' Equity).

(4) The increases in 2012 reflect assets and investments acquired, primarily related to the Caiman and Laser Acquisitions and our investment in ACMP, as well as debt and equity issuances.

(5) The increases in 2015, 2014, and 2013 reflects borrowings under WPZ's commercial paper program, which was initiated in 2013.

(6) Amounts for 2014 and preceding periods presented have been adjusted to reflect the early adoption of ASU 2015-03 and ASU 2015-15, which address the presentation of debt issuance costs (see Note 14 – Debt, Banking Arrangements, and Leases).

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, NGLs, and olefins. Our operations are located principally in the United States, but span from the deepwater Gulf of Mexico to the Canadian oil sands, and are organized into the Williams Partners and Williams NGL & Petchem Services reportable segments. All remaining business activities are included in Other.

Williams Partners

Williams Partners consists of our consolidated master limited partnership, WPZ, which includes gas pipeline and midstream businesses. The gas pipeline businesses include interstate natural gas pipelines and pipeline joint project investments; and the midstream businesses provide natural gas gathering, treating, and processing services; NGL production, fractionation, storage, marketing and transportation; deepwater production handling and crude oil transportation services; an olefin production business and is comprised of several wholly owned and partially owned subsidiaries and joint project investments. As of December 31, 2015, we own approximately 60 percent of the interests in WPZ, including the interests of the general partner which are wholly owned by us, and IDRs.

Williams Partners' gas pipeline businesses consist primarily of Transco and Northwest Pipeline. Our gas pipeline businesses also hold interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent equity-method investment in Gulfstream and a 41 percent interest in Constitution (a consolidated entity), which is under development. As of December 31, 2015, Transco and Northwest Pipeline own and operate a combined total of approximately 13,600 miles of pipelines with a total annual throughput of approximately 4,136 TBtu of natural gas and peak-day delivery capacity of approximately 15 MMdth of natural gas.

Williams Partners' midstream businesses primarily consist of (1) natural gas gathering, treating, and processing; (2) NGL fractionation, storage and transportation; (3) crude oil transportation; and (4) olefins production. The primary service areas are concentrated in major producing basins in Colorado, Texas, Oklahoma, Kansas, New Mexico, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio which include the Marcellus and Utica shale plays as well as the Eagle Ford, Haynesville, Barnett, Mid-Continent, and Niobrara areas. The midstream businesses include equity-method investments in natural gas gathering and processing assets and NGL fractionation and transportation assets, including a 62 percent equity-method investment in UEOM, a 50 percent equity-method investment in the Delaware basin gas gathering system in the Mid-Continent region, a 69 percent equity-method investment in Laurel Mountain Midstream, LLC, a 58 percent equity-method investment in Caiman Energy II, LLC, a 60 percent equity-method investment in Discovery Producer Services LLC, a 50 percent equity-method investment in Overland Pass Pipeline, LLC, and Appalachia Midstream Services, LLC, which owns an approximate average 45 percent equity-method investment in multiple gas gathering systems in the Marcellus Shale (Appalachia Midstream Investments).

The midstream businesses also include our Canadian midstream operations which are comprised of an oil sands offgas processing plant near Fort McMurray, Alberta and NGL/olefin fractionation facility at Redwater, Alberta, and the Boreal Pipeline.

Williams Partners' ongoing strategy is to safely and reliably operate large-scale, interstate natural gas transmission and midstream infrastructures 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 and investing in growing markets, including the deepwater Gulf of Mexico, the Marcellus Shale, the Gulf Coast Region, the Canadian oil sands, and areas of increasing natural gas demand.

Williams Partners' interstate transmission and related 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 little near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Williams NGL & Petchem Services

Williams NGL & Petchem Services is comprised of our Texas Belle pipeline and certain other domestic olefins pipeline assets and certain Canadian growth projects under development, including a propane dehydrogenation facility and a liquids extraction plant. The Williams NGL & Petchem Services segment is currently comprised primarily of projects under development and thus have had limited operating revenues to date.

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 2015, we paid a regular quarterly dividend of $0.64 per share, which was 12 percent higher than the same period last year.

Overview

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the year ended December 31, 2015, decreased $2.68 billion compared to the year ended December 31, 2014, primarily due to the absence of a $2.5 billion gain as a result of remeasuring our previous equity-method investment in ACMP to fair value, impairment charges associated with certain goodwill, equity-method investments, and other assets (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk), declines in NGL margins driven by 65 percent lower prices, higher depreciation expense caused by significant projects that have gone into service in 2014 and 2015, a gain of $154 million resulting from cash proceeds received for a contingency settlement in 2014, as well as increased interest expense associated with new debt issuances. These decreases were partially offset by new fee-based revenue associated with certain growth projects that were placed in service in 2014 and 2015 and the absence of equity losses in 2014 associated with the discontinuance of the Bluegrass Pipeline project. See additional discussion in Results of Operations.

Energy Transfer Merger Agreement

On September 28, 2015, we entered into an Agreement and Plan of Merger (Merger Agreement) with Energy Transfer Equity, L.P. (Energy Transfer) and certain of its affiliates. The Merger Agreement provides that, subject to the satisfaction of customary closing conditions, we will be merged with and into the newly formed Energy Transfer Corp LP (ETC) (ETC Merger), with ETC surviving the ETC Merger. Energy Transfer formed ETC as a limited partnership that will be treated as a corporation for U.S. federal income tax purposes. Upon completion of the ETC Merger, ETC will be publicly traded on the New York Stock Exchange under the symbol "ETC."

At the effective time of the ETC Merger, each issued and outstanding share of our common stock (except for certain shares such as those held by us or our subsidiaries and any held by ETC and its affiliates) will be canceled and automatically converted into the right to receive stock, cash, or a combination thereof as described in Note 1 of Notes to Consolidated Financial Statements.

In connection with the ETC Merger, Energy Transfer will subscribe for a number of ETC common shares at the transaction price, in exchange for the amount of cash needed by ETC to fund the cash portion of the Merger Consideration (the Parent Cash Deposit), and, as a result, based on the number of shares of Williams common stock outstanding as of the date thereof, will own approximately 19 percent of the outstanding ETC common shares immediately after the effective time of the ETC Merger.

Immediately following the completion of the ETC Merger and of the LE GP, LLC (the general partner for Energy Transfer) merger with and into Energy Transfer Equity GP, LLC, ETC will contribute to Energy Transfer all of the assets and liabilities of Williams in exchange for the issuance by Energy Transfer to ETC of a number of Energy Transfer Class E common units equal to the number of ETC common shares issued to our stockholders in the ETC Merger plus the number of ETC common shares issued to Energy Transfer in consideration for the Parent Cash Deposit (such contribution, together with the ETC Merger and the other transactions contemplated by the Merger Agreement, the Merger Transactions).

To address potential uncertainty as to how the newly listed ETC common shares, as a new security, will trade relative to Energy Transfer common units, each ETC common share issued in the ETC Merger, as well as the ETC common shares issued to Energy Transfer in connection with the Parent Cash Deposit, will have attached to it one contingent consideration right (CCR). The terms of the CCRs are fully described in the form of CCR Agreement attached to the Merger Agreement as Exhibit H to Exhibit 2.1 of our Current Report on Form 8-K dated September 29, 2015.

The receipt of the Merger Consideration is expected to be tax-free to our stockholders, except with respect to any cash consideration received.

We expect the transaction to close in the first half of 2016. Completion of the Merger Transactions is subject to the satisfaction or waiver of a number of customary closing conditions as set forth in the Merger Agreement, including approval of the ETC Merger by our stockholders, receipt of required regulatory approvals in connection with the Merger Transactions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and effectiveness of a registration statement on Form S-4 registering the ETC common shares (and attached CCRs) to be issued in connection with the Merger Transactions.

ETC filed its initial Form S-4 registration statement on November 24, 2015, and Amendment No. 1 to Form S-4 on January 12, 2016. On December 14, 2015, we and Energy Transfer issued a joint press release announcing the entry into a timing agreement with the United States Federal Trade Commission (FTC) pursuant to which both parties have agreed not to consummate ETC’s proposed acquisition of us until after the later of (i) 60 days after substantial compliance with the FTC’s request for additional information and documentary material and (ii) March 18, 2016.

Termination of WPZ Merger Agreement

On May 12, 2015, we entered into an agreement for a unit-for-stock transaction whereby we would have acquired all of the publicly held outstanding common units of WPZ in exchange for shares of our common stock (WPZ Merger Agreement).

On September 28, 2015, prior to our entry into the Merger Agreement, we entered into a Termination Agreement and Release (Termination Agreement), terminating the WPZ Merger Agreement. Under the terms of the Termination Agreement, we are required to pay a $428 million termination fee to WPZ, of which we currently own approximately 60 percent, including the interests of the general partner and IDRs. Such termination fee will settle through a reduction of quarterly incentive distributions we are entitled to receive from WPZ (such reduction not to exceed $209 million per quarter). The distributions from WPZ in November 2015 and February 2016 were each reduced by $209 million related to this termination fee.

Williams Partners

ACMP Merger

We owned an equity-method investment in ACMP until July 1, 2014, at which time we acquired all of the interests in ACMP held by Global Infrastructure Partners II (GIP) which included 50 percent of the general partner interest and 55.1 million limited partner units for $5.995 billion in cash (ACMP Acquisition).

On October 26, 2014, we announced that our consolidated master limited partnerships Pre-merger WPZ and ACMP entered into a merger agreement and on February 2, 2015, the merger was completed (ACMP Merger). The merged partnership is named Williams Partners L.P. Under the terms of the merger agreement, each ACMP unitholder received

1.06152 ACMP units for each ACMP unit owned immediately prior to the ACMP Merger. In conjunction with the ACMP Merger, each Pre-merger WPZ common unit held by the public was exchanged for 0.86672 ACMP common units. Each WPZ common unit held by us was exchanged for 0.80036 ACMP common units. Prior to the closing of the ACMP Merger, the Class D limited partner units of Pre-merger WPZ, all of which were held by us, were converted into common units on a one-for-one basis pursuant to the terms of the Pre-merger WPZ partnership agreement. Following the ACMP Merger, we own an approximate 60 percent interest in the merged partnership, including the general partner interest and incentive distribution rights.

Geismar Incident and plant expansion

On June 13, 2013, an explosion and fire occurred at Williams Partners' Geismar olefins plant. The incident rendered the facility temporarily inoperable (Geismar Incident).

Our total property damage and business interruption loss exceeded our $500 million policy limit. Since June 2013, we have settled claims associated with $480 million of available property damage and business interruption coverage for a total of $422 million. This total includes $126 million which we received in the second quarter of 2015. The remaining insurance limits total approximately $20 million and we are vigorously pursuing collection.

Leidy Southeast

In January 2016, Leidy Southeast was placed into service, which expands Transco's existing natural gas transmission system from the Marcellus Shale production region on Transco's Leidy Line in Pennsylvania to delivery points along its mainline as far south as Station 85 in west central Alabama. In March 2015, we began providing firm transportation service through the mainline portion of the project on an interim basis until the in-service date of the project as a whole. We placed the remainder of the project into service during January 2016 increasing capacity by 525 Mdth/d.

Utica and Haynesville gas gathering agreements

In September 2015, Williams announced an expansion of gas gathering services for a certain major producer customer in dry gas production areas of the Utica Shale in eastern Ohio and a consolidation of contracts in the Haynesville Shale in northwestern Louisiana.

In the Utica, WPZ executed a long-term fee-based contract that extends the length of certain acreage dedication to 2035, increases the area of dedication from 140,000 acres to 190,000 net acres and converts the cost-of-service mechanism to a fixed-fee structure with minimum volume commitments (MVCs).

A new Haynesville contract consolidates the Springridge and Mansfield contracts into a single agreement with a fixed-fee structure and extends the contract term to 2035. The consolidated contract is supported by MVCs and a drilling commitment to turn 140 equivalent wells online before the end of 2017.

Virginia Southside

In September 2015, Transco's Virginia Southside expansion from New Jersey to a power station in Virginia and delivery points in North Carolina was placed into service. On December 1, 2014, we placed a portion of the project into service, which enabled us to begin providing 250 Mdth/d of additional firm transportation service through the mainline portion of the project on an interim basis, until the in-service date of the project as a whole. We placed the remainder of the project into service in September 2015. In total, the project increased capacity by 270 Mdth/d.

Northeast Connector

In May 2015, the Northeast Connector project was placed into service, which increased firm transportation capacity by 100 Mdth/d from Transco's Station 195 in southeastern Pennsylvania to the Rockaway Delivery Lateral.

Rockaway Delivery Lateral

In May 2015, Transco's Rockaway Delivery Lateral expansion between Transco's transmission pipeline and the National Grid distribution system was placed in service, which enabled us to begin providing 647 Mdth/d of additional firm transportation service to a distribution system in New York.

Mobile Bay South III

In April 2015, Transco's Mobile Bay South III expansion south from Station 85 in west central Alabama to delivery points along the Mobile Bay line was placed into service, which enabled us to begin providing 225 Mdth/d of additional firm transportation service on the Mobile Bay Lateral.

Bucking Horse gas processing facility

The Bucking Horse gas processing plant (Bucking Horse) began operating in February 2015. Bucking Horse is located in Converse County, Wyoming, and adds 120 MMcf/d of processing capacity in the Powder River basin Niobrara Shale play. Processed volumes at Bucking Horse have continued to increase throughout 2015 as existing rich gas production was re-directed from other third-party processing facilities. Bucking Horse has led to higher gathering volumes in 2015 as previously curtailed production has increased due to the additional processing capability.

Eagle Ford gathering system

In May 2015, WPZ acquired a gathering system comprised of approximately 140 miles of pipeline and a sour gas compression facility capable of handling up to 100 MMcf/d in the Eagle Ford shale for $112 million. The acquisition is contributing approximately 20 MMcf/d to the existing Eagle Ford throughput of approximately 400 MMcf/d.

UEOM

In June 2015, WPZ acquired an approximate 13 percent equity interest in UEOM for approximately $357 million, increasing our ownership from 49 percent to approximately 62 percent.

Volatile commodity prices

NGL margins were approximately 59 percent lower in 2015 compared to 2014 driven primarily by 58 percent lower non-ethane prices partially offset by lower 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 following graph illustrates the effects of this margin volatility and NGL production and sales volumes, as well as the margin differential between ethane and non-ethane products and the relative mix of those products.

The potential impact of commodity price volatility on our business is further discussed in the following Company Outlook.

Williams NGL & Petchem Services

Texas Belle Pipeline

In March 2015, the Texas Belle Pipeline (Texas Belle) went into service in the Houston Ship Channel area. Texas Belle is a 32-mile open access, service focused pipeline that transports NGLs and was designed to deliver butanes and natural gasolines from Mont Belvieu, Texas, to new demand in the Houston Ship Channel area.

Company Outlook

As previously discussed, we entered into a Merger Agreement with Energy Transfer and certain of its affiliates and expect the ETC Merger to close in the first half of 2016. The following discussion reflects our operating plan for 2016.

Our strategy is to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas, natural gas products, and crude oil that exists in North America. We seek to accomplish this through further developing our scale positions in current key markets and basins and entering new growth markets and basins where we can become the large-scale service provider. We will 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.

This strategy remains intact and we continue to execute on infrastructure projects that serve long-term natural gas needs. We expect commodity prices to remain challenged and costs of capital to remain sharply higher throughout

2016 as compared to 2015. Anticipating these conditions, our business plan for 2016 includes significant reductions in capital investment and expenses from our previous plans. In addition, we expect proceeds from planned asset monetizations in excess of $1 billion during 2016.

Our growth capital and investment expenditures in 2016 are expected to total $2.2 billion, which is a $1.5 billion reduction from our previous plans. Approximately $1.3 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining non-interstate pipeline growth capital spending in 2016 primarily reflects investment in gathering and processing systems limited to known new producer volumes, including wells drilled and completed awaiting connecting infrastructure. 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.

Fee-based businesses are a significant component of our portfolio, which serves to somewhat reduce the influence of commodity price fluctuations on our operating results and cash flows. However, producer activities are being impacted by lower energy commodity prices which will reduce our gathering volumes. The credit profiles of certain of our producer customers are increasingly challenged by the current market conditions, which ultimately may result in a further reduction of our gathering volumes. Such reductions as well as further or prolonged declines in energy commodity prices may result in noncash impairments of our assets.

Commodity margins are highly dependent upon regional supply/demand balances of natural gas as they relate to NGL margins, while olefins are impacted by global supply and demand fundamentals. We anticipate the following trends in energy commodity prices in 2016, compared to 2015 that may impact our operating results and cash flows:

- Natural gas and ethane prices are expected to be lower.
- Non-ethane prices, including propane, are expected to be lower.
- Olefins prices, including propylene, ethylene, and the overall ethylene crack spread, are expected to be lower.

In 2016, we anticipate our operating results will reflect increases from our fee-based businesses primarily as a result of Transco projects placed in service in 2015 and those anticipated to be placed in service in 2016, increases in our olefins volumes associated with a full year of operations at our Geismar plant following its 2015 repair and expansion, and anticipated lower general and administrative costs. Additionally, we anticipate these improvements will be partially offset by the absence of operating results associated with certain asset monetizations, lower NGL margins, and additional operating expenses associated with growth projects placed in service in 2015 and those anticipated to be placed in service in 2016.

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

- Further downgrades of our credit ratings and associated increase in cost of borrowings;
- Higher cost of capital and/or limited availability of capital due to a change in our financial condition, interest rates, market or industry conditions;
- Counterparty credit and performance risk, including that of Chesapeake Energy Corporation and its affiliates;
- Inability to execute or delay in completing planned asset monetizations;
- Delay in capturing planned cost reductions;
- Lower than anticipated energy commodity prices and margins;
- Decreased volumes from third parties served by our midstream business;
- Unexpected significant increases in capital expenditures or delays in capital project execution;

- Lower than expected distributions, including IDRs, from WPZ;
- General economic, financial markets, or further industry downturn;
- Lower than expected levels of cash flow from operations;
- Changes in the political and regulatory environments;
- Physical damages to facilities, including damage to offshore facilities by named windstorms;
- Reduced availability of insurance coverage.

We continue to address these risks through maintaining a strong financial position and liquidity, as well as through managing a diversified portfolio of energy infrastructure assets which continue to serve key markets and basins in North America.

Expansion Projects

Our ongoing major expansion projects include the following:

Williams Partners

Access Midstream Projects

We plan to expand our gathering infrastructure in the Eagle Ford, Utica, and Marcellus shale regions in order to meet our customers' production plans. The expansion of the gathering infrastructure includes the addition of new facilities, well connections, and gathering pipeline to the existing systems.

Oak Grove Expansion

We plan to expand our processing capacity at our Oak Grove facility by adding a second 200MMcf/d cryogenic natural gas processing plant, which, based on our customers' needs, is expected to be placed into service in 2019.

Susquehanna Supply Hub

We will continue to expand the gathering system in the Susquehanna Supply Hub in northeastern Pennsylvania that is needed to meet our customers' production plans. The expansion of the gathering infrastructure includes additional compression and gathering pipeline to the existing system.

Atlantic Sunrise

In March 2015, we filed an application with the FERC to expand 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 plan to place the project into service during the second half of 2017, assuming timely receipt of all necessary regulatory approvals, and it is expected to increase capacity by 1,700 Mdth/d.

Constitution Pipeline

In December 2014, we received approval from the FERC to construct and operate the jointly owned Constitution pipeline. We also received a Notice of Complete Application from the New York Department of Environmental Conservation (NYDEC) in December 2014, but we continue to seek issuance of Clean Water Act Section 401 certification by the NYDEC. We currently own 41 percent of Constitution with three other parties holding 25 percent, 24 percent, and 10 percent, respectively. We will be the operator of Constitution. The 124-mile Constitution pipeline will connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York. We plan to place the project into service in the fourth quarter of 2016, assuming timely receipt of all necessary regulatory approvals, with an expected capacity of 650 Mdth/d.

Rock Springs

In March 2015, we received approval from the FERC to expand Transco's existing natural gas transmission system from New Jersey to a proposed generation facility in Maryland. The project is planned to be placed into service in third quarter 2016 and is expected to increase capacity by 192 Mdth/d.

Hillabee

In February 2016, the FERC issued a certificate order for the initial phases of Transco's Hillabee Expansion Project. We may seek rehearing of certain aspects of the FERC order. The Hillabee Expansion Project involves an expansion of Transco's existing natural gas transmission system from Station 85 in west central Alabama to a proposed new interconnection with Sabal Trail Transmission's system in Alabama. The project will be constructed in phases, and all of the project expansion capacity will be leased to Sabal Trail Transmission. We plan to place the initial phases of the project into service during the second quarters of 2017 and 2020, assuming timely receipt of all necessary regulatory approvals, and together they are expected to increase capacity by 1,025 Mdth/d.

Gulf Trace

In October 2015, we received approval from the FERC to expand Transco's existing natural gas transmission system together with greenfield facilities to provide incremental firm transportation capacity from Station 65 in St. Helena Parish, Louisiana westward to a new interconnection with Sabine Pass Liquefaction in Cameron Parish, Louisiana. We plan to place the project into service during the first quarter of 2017, assuming timely receipt of all other necessary regulatory approvals, and it is expected to increase capacity by 1,200 Mdth/d.

Dalton

In March 2015, we filed an application with the FERC to expand Transco's existing natural gas transmission system together with greenfield facilities to provide incremental firm transportation capacity from Station 210 in New Jersey to markets in northwest Georgia. We plan to place the project into service in 2017, assuming timely receipt of all necessary regulatory approvals, and it is expected to increase capacity by 448 Mdth/d.

Garden State

In February 2015, we filed an application with the FERC to expand 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. The project will be constructed in phases and is expected to increase capacity by 180 Mdth/d. We plan to place the initial phase of the project into service during the fourth quarter of 2016 and the remaining portion in the third quarter of 2017, assuming timely receipt of all necessary regulatory approvals.

Virginia Southside II

In March 2015, we filed an application with the FERC to expand Transco's existing natural gas transmission system together with greenfield facilities to provide incremental firm transportation capacity from New Jersey and Virginia to a new lateral extending from our Brunswick Lateral in Virginia. We plan to place the project into service during the fourth quarter of 2017, assuming timely receipt of all necessary regulatory approvals, and expect it to increase capacity by 250 Mdth/d.

New York Bay

In July 2015, we filed an application with the FERC to expand Transco's existing natural gas transmission system to provide incremental firm transportation capacity from Pennsylvania to the Rockaway Delivery Lateral transfer point and the Narrows meter station in Richmond County, New York. We plan to place the project into service during the fourth quarter of 2017, assuming timely receipt of all necessary regulatory approvals, and it is expected to increase capacity by 115 Mdth/d.

Redwater Expansion

As part of a long-term agreement to provide gas processing services to a second bitumen upgrader in Canada’s oil sands near Fort McMurray, Alberta, we are increasing the capacity of the Redwater facilities where NGL/olefins mixtures will be fractionated into an ethane/ethylene mix, propane, polymer grade propylene, normal butane, an alkylation feed and condensate. This capacity increase is expected to be placed into service during the first quarter of 2016.

Williams NGL & Petchem Services

Canadian PDH Facility

We are developing a project to construct a PDH facility in Alberta that will significantly increase production of polymer-grade propylene. The new PDH facility would produce approximately 1.1 billion pounds annually. Due to our current capital allocation considerations, in the first quarter of 2016, management determined to substantially slow the pace of development activities, limit further investment, and proceed with a strategy that could result in the potential sale of this project, entering into a partnership to fund additional development, or deferring development of the project.

Canadian NGL Infrastructure Expansion

As part of a long-term agreement to provide gas processing to a second bitumen upgrader in Canada’s oil sands near Fort McMurray, Alberta, we are building a new liquids extraction plant and an extension of the Boreal Pipeline, owned by our Williams Partners segment. The extension will enable transportation of the NGL/olefins mixture on the Boreal pipeline from the new liquids extraction plant to the expanded Redwater facilities, owned by our Williams Partners segment. We plan to place the new liquids extraction plant and interconnection with Boreal into service during the first quarter of 2016, and expect initial NGL/olefins recoveries of approximately 12 Mbbls/d. To mitigate ethane price risk associated with our processing services, we have a long-term agreement with a minimum price for ethane sales to a third-party customer.

Gulf Coast NGL and Olefin Infrastructure Expansion

Certain previously acquired liquids pipelines in the Gulf Coast region will be combined with an organic build-out of several projects to expand our petrochemical services in that region. The projects include the construction and commissioning of pipeline systems capable of transporting various purity natural gas liquids and olefins products in the Gulf Coast region. In response to the current conditions in the midstream industry, we are slowing the pace of development and may seek partners for these projects.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. We have reviewed the selection, application, and disclosure of these critical accounting estimates with our Audit Committee. 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, expected rate of compensation increase, health care cost trend rates, 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 9 – 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	$(9)	$11	$(130)	$154
Expected long-term rate of return on plan assets	(13)	13	—	—
Rate of compensation increase	3	(2)	9	(7)
Other postretirement benefits:				
Discount rate	1	2	(21)	26
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	1	(1)	7	(6)

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, which are weighted toward domestic and international equity securities. We develop our expectations using input from several external sources, including consultation with our third-party independent investment consultant. The forward-looking capital market projections are developed using a consensus of economists' expectations for inflation, GDP growth, and dividend yield along with expected changes in risk premiums. 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.

In 2015, the benefit plans' assets outperformed their respective benchmarks for non-U.S. equity and fixed income strategies, but underperformed the respective benchmark for U.S. equity strategies. While the 2015 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 these expected rates of return. Our expected long-term rate of return on plan assets used for our pension plans was 6.38 percent in 2015. The 2015 actual return on plan assets for our pension plans was a loss of approximately 1.0 percent. The 10-year average rate of return on pension plan assets through December 2015 was approximately 4.4 percent.

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

The assumed health care cost trend rates are based on national trend rates adjusted for our actual historical cost rates and plan design. An increase in this rate causes the other postretirement benefit obligation and cost to increase.

57

Goodwill

As disclosed within the Critical Accounting Estimates discussion in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations of our Form 10-Q dated October 29, 2015, we performed an interim impairment evaluation of the goodwill associated with the Access Midstream reporting unit as of September 30, 2015. The goodwill associated with this reporting unit was initially recorded during the third quarter of 2014 in conjunction with our acquisition of ACMP. At September 30, 2015, the fair value of this reporting unit, determined using an income approach, exceeded the carrying value and thus no impairment was recorded. For such a measurement, the book basis of the reporting unit was reduced by the associated deferred tax liabilities. We disclosed that the evaluation utilized a discount rate of approximately 9.4 percent.

On October 1, 2015, we performed our annual review of the goodwill within the Northeast G&P and West reporting units. At that date, the fair value of each reporting unit exceeded the carrying value and no impairment was recorded. The discount rates utilized for the reporting units at October 1, 2015, were approximately 10.8 percent and 9.6 percent, respectively.

During the fourth quarter of 2015, we observed a significant decline in the market values of WPZ and comparable midstream companies within the industry. This served to reduce our estimate of enterprise value and increased our estimates of discount rates. As a result, we performed an impairment assessment of the goodwill associated with all of our reporting units as of December 31, 2015. Prior to this assessment, the book value of goodwill by reporting unit was as follows:

Reporting Segment	Reporting Unit	Goodwill (Millions)
Williams Partners	Access Midstream	$452
Williams Partners	Northeast G&P	646
Williams Partners	West	47
		$1,145

For our evaluation at December 31, 2015, we continued to estimate the fair value of each reporting unit based on an income approach utilizing discount rates specific to the underlying businesses of each reporting unit. These discount rates considered variables unique to each business area, including equity yields of comparable midstream businesses, expectations for future growth and customer performance considerations. Weighted-average discount rates utilized for the reporting units were 12.8 percent for Access Midstream, 12.5 percent for Northeast G&P, and 10.4 percent for the West. As a result of the increases in discount rates during the fourth quarter, coupled with certain reductions in estimated future cash flows determined during the same period, the fair values of the Access Midstream and Northeast G&P reporting units were determined to be below their respective carrying values. For these reporting units, we calculated the implied fair value of goodwill by performing a hypothetical application of the acquisition method wherein the estimated fair value was assigned to the underlying assets and liabilities of each reporting unit. As a result of this analysis, we determined that the goodwill associated with each of these reporting units was fully impaired. For the West reporting unit, the estimated fair value significantly exceeded the carrying value and no impairment was recorded.

These results were corroborated with a market capitalization analysis whereby we reconciled the enterprise value at December 31, 2015, to the aggregate fair value of all of the reporting units and operating areas.

Judgments and assumptions are inherent in our estimates of future cash flows, discount rates, and market measures used to evaluate these assets. The use of alternate judgments and assumptions could result in a different calculation of fair value, which could ultimately result in the recognition of a different impairment charge in the consolidated financial statements.

During the first quarter of 2016 to-date, we have observed further significant decline in the market value of WPZ. Continuation of this condition may require evaluating our remaining goodwill for potential impairment in the future.

Equity-method Investments

As disclosed within the Critical Accounting Estimates discussion in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations of our Form 10-Q dated October 29, 2015, in the third quarter of 2015 in response to declining market conditions, we assessed whether the carrying amounts of certain of our equity-method investments exceeded their fair value. As a result, we recognized other-than-temporary impairment charges of $458 million and $3 million in the third-quarter related to our equity-method investments in the Delaware basin gas gathering system and certain of the Appalachia Midstream Investments, respectively. The historical carrying value of these investments was initially recorded based on estimated fair value during the third quarter of 2014 in conjunction with our acquisition of ACMP. We estimated the fair value of these investments using an income approach and discount rates of 11.8 percent and 8.8 percent, respectively.

In response to declining market conditions in the fourth quarter as previously discussed, we again assessed whether the carrying amounts of certain of our equity-method investments exceeded their fair value. In the fourth quarter, we recognized additional impairment charges of $45 million and $559 million related to the Delaware basin gas gathering system and certain of the Appalachia Midstream Investments, respectively, and impairment charges of $241 million and $45 million associated with UEOM and Laurel Mountain, respectively. The historical carrying value of our original 49 percent interest in UEOM was initially recorded based on estimated fair value during the third quarter of 2014 in conjunction with our acquisition of ACMP and the remaining 13 percent interest reflected our cost of acquiring that additional interest in June 2015.

We estimated the fair value of these investments using an income approach and discounts rates ranging from 10.8 percent to 14.4 percent. These discount rates considered variables unique to each business area, including equity yields of comparable midstream businesses, expectations for future growth and customer performance considerations. We estimate that an overall increase in the discount rates utilized of 50 basis points would have resulted in additional impairment charges on these investments of approximately $286 million.

Judgments and assumptions are inherent in our estimates of future cash flows, discount rates, and market measures utilized. The use of alternate judgments and assumptions could result in a different calculation of fair value, which could ultimately result in the recognition of a different impairment charge in the consolidated financial statements.

At December 31, 2015, our Consolidated Balance Sheet includes approximately $7.3 billion of investments that are accounted for under the equity-method of accounting. We evaluate these investments for impairment when events or changes in circumstances indicate, in our management's 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. We generally estimate the fair value of our investments using an income approach where significant judgments and assumptions include expected future cash flows and the appropriate discount rate. In some cases, we may utilize a form of market approach to estimate the fair value of our investments.

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. Events or changes in circumstances that may be indicative of an other-than-temporary decline in value will vary by investment, but may include:

- A significant or sustained decline in the market value of an investee;
- Lower than expected cash distributions from investees;
- Significant asset impairments or operating losses recognized by investees;
- Significant delays in or lack of producer development or significant declines in producer volumes in markets served by investees;
- Significant delays in or failure to complete significant growth projects of investees.

During the first quarter of 2016 and through the date of this filing, we have observed further significant decline in the market value of WPZ. Continuation of this condition and/or further decline in such value will likely require the evaluation of certain of our equity investments for potential impairment at March 31, 2016, including those that were impaired at December 31, 2015. As a result, there is the potential for significant additional noncash impairments of our investments in the future.

Capitalized Project Development Costs

As of December 31, 2015 our Consolidated Balance Sheet includes approximately $221 million of capitalized costs associated with a limited number of developing and deferred projects, some of which are considered probable of future completion while certain others are only reasonably possible of completion. Following the significant decline in energy commodity prices and market values within our industry in 2015, we either reviewed these capitalized project costs for indicators of impairment or evaluated them for impairment as of December 31, 2015. Where performed, our impairment evaluations considered probability-weighted scenarios of undiscounted future net cash flows, including reasonably possible scenarios assuming the construction and operation of the underlying projects.

As a result of these impairment evaluations, we recognized impairment charges of $158 million associated with certain of these projects. This includes a $94 million impairment charge within our Williams Partners segment associated with development costs for a gas processing plant for which completion is now considered remote due to the unfavorable impact of low natural gas prices on customer drilling activities, and a $64 million impairment charge within our Williams NGL & Petchem Services segment associated with costs for an olefins pipeline project that is now considered remote due to the lack of customer interest.

We will continue to review and evaluate capitalized project costs for impairment in the future if we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Such events or changes in circumstances may include changes in customer requirements associated with these projects, as well as overall changes in market demand. If, in a future evaluation, our carrying value for any of the projects exceeds the undiscounted future net cash flows, we will recognize an impairment for the difference between the carrying value and our estimate of fair value of the assets.

One of these projects is a Canadian PDH facility for which we have capitalized project development costs of approximately $128 million at December 31, 2015. Due to our current capital allocation considerations, management determined in the first quarter of 2016 to substantially slow the pace of development activities, limit further investment, and proceed with a strategy that could result in the potential sale of this project, entering into a partnership to fund additional development, or deferring development of the project. We have evaluated the recoverability of costs associated with this project under various scenarios of undiscounted future cash flows from the potential outcomes and determined that no impairment was required. As this strategy proceeds and our cash flow and value assumptions are updated, it is possible that some portion of these costs may be determined to be unrecoverable and thus result in an impairment.

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.

At December 31, 2015, our Consolidated Balance Sheet includes property, plant, and equipment and intangible assets totaling $29.6 billion and $10.0 billion, respectively. Further declines in energy commodity prices and conditions in our industry may affect our estimates of future cash flows and impact assumptions about the performance of our customers. Such indicators may cause us to evaluate these assets for potential impairment in future periods.

60

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.

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, 2015. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2015	$ Change from 2014*	% Change from 2014*	2014	$ Change from 2013*	% Change from 2013*	2013
	(Millions)						
Revenues:							
Service revenues	$5,164	+1,048	+25 %	$4,116	+1,177	+40 %	$2,939
Product sales	2,196	-1,325	-38 %	3,521	-400	-10 %	3,921
Total revenues	7,360			7,637			6,860
Costs and expenses:							
Product costs	1,779	+1,237	+41 %	3,016	+11	— %	3,027
Operating and maintenance expenses	1,655	-163	-11 %	1,492	-395	-36 %	1,097
Depreciation and amortization expenses	1,738	-562	-48 %	1,176	-361	-44 %	815
Selling, general, and administrative expenses	741	-80	-12 %	661	-149	-29 %	512
Impairment of goodwill	1,098	-1,098	NM	—	—	— %	—
Net insurance recoveries – Geismar Incident	(126)	-106	-46 %	(232)	+192	NM	(40)
Other (income) expense – net	249	-294	NM	(45)	+119	NM	74
Total costs and expenses	7,134			6,068			5,485
Operating income (loss)	226			1,569			1,375
Equity earnings (losses)	335	+191	+133 %	144	+10	+7 %	134
Gain on remeasurement of equity-method investment	—	-2,544	-100 %	2,544	+2,544	NM	—
Impairment of equity-method investments	(1,359)	-1,359	NM	—	—	— %	—
Other investing income (loss) – net	27	-16	-37 %	43	-38	-47 %	81
Interest expense	(1,044)	-297	-40 %	(747)	-237	-46 %	(510)
Other income (expense) – net	102	+71	NM	31	+31	NM	—
Income (loss) from continuing operations before income taxes	(1,713)			3,584			1,080
Provision (benefit) for income taxes	(399)	+1,648	NM	1,249	-848	NM	401
Income (loss) from continuing operations	(1,314)			2,335			679
Income (loss) from discontinued operations	—	-4	-100 %	4	+15	NM	(11)
Net income (loss)	(1,314)			2,339			668
Less: Net income (loss) attributable to noncontrolling interests	(743)	+968	NM	225	+13	+5 %	238
Net income (loss) attributable to The Williams Companies, Inc.	$(571)			$2,114			$430

*

+ = 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.

2015 vs. 2014

Service revenues increased primarily due to additional revenues associated with a full year of ACMP operations in 2015, increased revenues associated with the start-up of operations at Gulfstar One during the fourth quarter of 2014, and an increase in Transco's natural gas transportation fees due to new projects placed in service in 2014 and 2015. Revenues from operations associated with the ACMP Acquisition and the northeast region also increased due to higher volumes related to new well connects. A decrease in Canadian construction management revenues, reflecting a shift to internal customer construction projects, partially offset these increases.

Product sales decreased due to a decrease in marketing revenues primarily associated with lower prices across all products, partially offset by higher non-ethane volumes, and a decrease in revenues from our equity NGLs reflecting lower NGL prices, partially offset by higher NGL volumes. Product sales also decreased due to a decrease in olefin sales related to our Canadian operations and our RGP Splitter. The Canadian decrease was primarily due to lower prices partially offset by higher propylene volumes. The RGP Splitter decrease was primarily due to lower propane sales reflecting lower per-unit prices and lower propylene sales. These decreases are partially offset by an increase in olefin sales primarily due to resuming our Geismar operations during 2015.

Product costs decreased due to a decrease in marketing purchases primarily associated with lower per-unit costs, partially offset by higher non-ethane volumes, and a decrease in natural gas purchases associated with the production of equity NGLs primarily due to lower natural gas prices, partially offset by higher volumes. Product costs also decreased due to lower feedstock purchases in our Canadian operations primarily due to lower per-unit feedstock costs across all products as well as lower costs at our RGP Splitter driven by lower per-unit costs, partially offset by significantly higher volumes in 2015. These decreases are partially offset by an increase in olefin feedstock purchases primarily associated with resuming our Geismar operations.

Operating and maintenance expenses increased primarily due to new expenses associated with operations acquired in the ACMP Acquisition, increased growth of operating activity in certain areas, increased maintenance and repair expenses, and the return to operations of the Geismar plant. These increases are partially offset by a decrease in Canadian construction management expenses that reflect a shift to internal customer construction projects.

Depreciation and amortization expenses increased primarily due to new expenses associated with operations acquired in the ACMP Acquisition and from depreciation on new projects placed in service, including Gulfstar One and the Geismar expansion.

Selling, general, and administrative expenses (SG&A) increased primarily due to administrative expenses associated with operations acquired in the ACMP Acquisition, including $31 million higher ACMP merger and transition-related costs, partially offset by the absence of $16 million of acquisition costs incurred in 2014. In addition, 2015 includes $32 million of costs associated with our evaluation of strategic alternatives. These increases are partially offset by the absence of $18 million of project development costs incurred in 2014 related to the Bluegrass Pipeline reflecting 100 percent of such costs. The 50 percent noncontrolling interest share of these costs are presented in Net income (loss) attributable to noncontrolling interests.

Impairment of goodwill reflects a 2015 impairment charge associated with certain goodwill (see Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements).

Net insurance recoveries – Geismar Incident changed unfavorably primarily due to the receipt of $126 million of insurance recoveries in 2015 as compared to the receipt of $246 million of insurance recoveries in 2014. (See Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements.)

Other (income) expense – net within Operating income (loss) changed unfavorably primarily due to increased impairments in 2015, the absence of $154 million of cash proceeds received in 2014 related to a contingency settlement gain, and the absence of a $12 million net gain recognized in 2014 related to a partial acreage dedication release. (See Note 6 – Other Income and Expenses.)

Operating income (loss) changed unfavorably primarily due to 2015 impairment of goodwill, higher impairments of certain assets, higher depreciation, operating, and maintenance expenses related to construction projects placed in

service and the start-up of the Geismar plant, $229 million lower NGL margins driven by lower prices, lower insurance recoveries related to the Geismar Incident, higher costs related to the merger and integration of ACMP into WPZ, and 2015 strategic alternative expenses. These decreases were partially offset by increased service revenues related to construction projects placed in service, $116 million higher olefin margins primarily due to our Geismar plant that returned to operations in 2015, and contributions from the operations acquired in the ACMP Acquisition.

Equity earnings (losses) changed favorably primarily due to the absence of equity losses from Bluegrass Pipeline and Moss Lake in 2014 and due to contributions from investments acquired in the ACMP Acquisition. In addition, equity earnings at Discovery increased $76 million primarily related to the completion of the Keathley Canyon Connector in early 2015. These changes were partially offset by $33 million of losses associated with our share of impairments recognized at equity investees in 2015. (See Note 5 – Investing Activities of Notes to Consolidated Financial Statements.)

Gain on remeasurement of equity-method investment reflects the 2014 gain recognized as a result of remeasuring to fair value the equity-method investment that we held before we acquired a controlling interest in ACMP. (See Note 2 – Acquisitions of Notes to Consolidated Financial Statements.)

Impairment of equity-method investments reflects 2015 impairment charges associated with certain 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 changed unfavorably primarily due to lower interest income associated with a receivable related to the sale of certain former Venezuela assets.

Interest expense increased due to a $230 million increase in Interest incurred primarily due to new debt issuances in 2014 and 2015 and interest expense associated with debt assumed in conjunction with the ACMP Acquisition. This increase was partially offset by lower interest due to 2015 debt retirements and the absence of a $9 million ACMP Acquisition transaction-related financing fee incurred in the second quarter of 2014. In addition, Interest capitalized decreased $67 million primarily related to construction projects that have been placed into service. (See Note 2 – Acquisitions and 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 $43 million benefit related to an increase in allowance for equity funds used during construction (AFUDC) associated with an increase in spending on various Transco expansion projects and Constitution, a $14 million gain on early debt retirement in April 2015, and a $9 million contingency gain settlement.

Provision (benefit) for income taxes changed favorably primarily due to lower pretax income in 2015. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both years.

The favorable change in Net income (loss) attributable to noncontrolling interests related to our investment in WPZ is primarily due to lower operating results at WPZ, our increased percentage of limited partner ownership of WPZ, and the impact of increased income allocated to the WPZ general partner, held by us, associated with IDRs. These changes are partially offset by an unfavorable change related to our investment in Gulfstar One associated with its start up in 2014.

2014 vs. 2013

Service revenues increased primarily due to contributions associated with the ACMP Acquisition beginning in third quarter 2014, including $167 million of minimum volume commitment fees, and due to new Canadian construction management services performed for third parties reported within the Other segment. Gathering fees increased driven by higher volumes and a net increase in gathering rates primarily in the Susquehanna Supply Hub. Natural gas transportation fee revenues increased primarily associated with expansion projects placed in service at Transco in 2013. In addition, Service revenues increased related to new processing, fractionation, and transportation fees from Ohio Valley Midstream facilities that were placed in service in 2013 and 2014.

Product sales decreased primarily due to lower olefin sales volumes associated with the lack of production in 2014 as a result of the Geismar Incident, partially offset by an increase in olefin sales on the RGP splitter primarily associated with higher volumes. In addition, equity NGL sales decreased primarily reflecting lower non-ethane volumes, partially offset by higher average ethane per-unit sales prices. Crude oil, natural gas, and other marketing revenues decreased primarily related to lower volumes, while NGL marketing revenues increased primarily related to higher volumes partially offset by lower NGL prices.

Product costs decreased primarily due to lower olefin feedstock purchases related to the lack of production in 2014 as a result of the Geismar Incident. In addition, natural gas purchases associated with the production of equity NGLs decreased slightly reflecting lower volumes, which were substantially offset by higher natural gas prices. These decreases were partially offset by an increase in lower-of-cost-or-market adjustments due to significant declines in NGL prices during the fourth quarter of 2014 and lower crude oil, natural gas, and olefin volumes, partially offset by higher NGL volumes.

Operating and maintenance expenses increased primarily due to costs incurred associated with new Canadian construction management services performed for third parties. In addition, increases are due to expenses associated with operations acquired in the ACMP Acquisition beginning in third quarter 2014, including $15 million of transition-related costs, expenses incurred in 2014 associated with the installation of certain safety equipment at the Geismar plant, and higher maintenance and growth in the our operations in the Northeast region of the U.S. These increases were partially offset by a net increase in system gains and reduced gathering fuel expense in the western region operations.

Depreciation and amortization expenses increased primarily associated with assets acquired in the ACMP Acquisition beginning in third quarter 2014 and due to depreciation on new projects placed in service.

SG&A increased primarily due to operations acquired in the ACMP Acquisition beginning in third quarter 2014 including $52 million of acquisition, merger, and transition-related costs recognized in 2014, as well as $18 million of project development costs incurred in 2014 related to the Bluegrass Pipeline reflecting 100 percent of such costs. The 50 percent noncontrolling interest share of these costs are presented in Net income (loss) attributable to noncontrolling interests. In addition, SG&A increased in the Northeast region of the U.S. related to significant operational growth driven by higher gathering fees associated with higher volumes from new well connections and the completion of various compression projects.

The favorable change in Net insurance recoveries – Geismar Incident is primarily due to the receipt of $246 million of insurance recoveries in 2014, compared to the receipt of $50 million of insurance recoveries in 2013.

Other (income) expense – net within Operating income (loss) includes the following increases to net income:

- $154 million of cash proceeds received in 2014 related to a contingency settlement gain;
- The absence of a $25 million accrued loss recognized in 2013 associated with a producer claim against us;
- The absence of a $20 million write-off in 2013 for certain pipeline assets;
- The absence of $12 million of expense recognized in 2013 and $3 million of expense reversal in 2014, related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates;
- A $12 million net gain recognized in 2014 related to the settlement of a partial acreage dedication release.

Other (income) expense – net within Operating income (loss) includes the following decreases to net income:

- $52 million of impairment charges recognized in 2014 related to certain assets;
- The absence of $16 million of income from insurance recoveries in 2013 related to the abandonment of certain Eminence storage assets;
- $10 million loss on the sale of certain assets in 2014;
- $9 million of expenses in excess of the insurable limit associated with the Geismar Incident;

- A $9 million increase in expenses associated with a regulatory liability for certain employee costs;
- The absence of a $9 million involuntary conversion gain recognized in 2013 related to a 2012 furnace fire at our Geismar olefins plant.

Operating income (loss) changed favorably primarily due to increased service revenues at Williams Partners associated with higher gathering volumes and new assets placed in service, a $192 million increase in net insurance recoveries related to the Geismar Incident, $167 million of minimum volume commitment fee revenue at Williams Partners related to operations acquired in the ACMP Acquisition, and $154 million of cash proceeds in 2014 related to a contingency gain settlement. These increases are partially offset by $192 million lower olefin margins, $130 million lower NGL margins and $59 million lower marketing margins, as well as higher operating costs at Williams Partners and higher impairment charges recognized in 2014.

Equity earnings (losses) changed favorably primarily due to the recognition of $96 million of equity earnings in the second half of 2014 related to equity investments acquired in the ACMP Acquisition, and an increase in equity earnings from Caiman II and Laurel Mountain. These increases are partially offset by $78 million of equity losses from Bluegrass Pipeline and Moss Lake in 2014 related primarily to the underlying write-off of previously capitalized project development costs, $19 million of equity losses associated with acquisition-related compensation expenses resulting from the ACMP Acquisition, and $17 million lower equity earnings related to our equity-method investment in ACMP since we consolidate this investment as of July 1, 2014.

Gain on remeasurement of equity-method investment represents the gain we recognized as a result of remeasuring to fair value the equity-method investment that we held before we acquired a controlling interest in ACMP.

Other investing income (loss) – net changed unfavorably primarily due to $26 million lower gains resulting from ACMP's equity issuances prior to our consolidation of that entity beginning in third quarter 2014 and lower interest income.

Interest expense increased due to a $277 million increase in Interest incurred primarily due to new debt issuances in the fourth quarter of 2013 and the first half of 2014, as well as combining ACMP's debt in third quarter 2014, and $9 million of ACMP Acquisition-related financing costs incurred in 2014. The increase in Interest incurred is partially offset by an increase of $40 million in Interest capitalized related to construction projects in progress.

Other income (expense) – net changed favorably primarily due to the benefit from the equity AFUDC associated with ongoing capital projects within our regulated operations.

Provision (benefit) for income taxes changed unfavorably primarily due to higher pretax income in 2014. This is partially offset by the absence of $99 million deferred income tax expense recognized in 2013, and a benefit of $34 million recorded in 2014 related to the undistributed earnings of certain foreign operations that are no longer considered permanently reinvested. See Note 7 – Provision (Benefit) for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both years.

Income (loss) from discontinued operations changed favorably primarily due to the absence of a $15 million pretax charge resulting from an unfavorable ruling associated with our former Alaska refinery related to the Trans-Alaska Pipeline System Quality Bank in 2013.

The favorable change in Net income attributable to noncontrolling interests includes the following:

- $95 million favorable for our investment in WPZ primarily due to the impact of increased income allocated to the WPZ general partner associated with IDRs;
- $9 million favorable for our investment in Bluegrass Pipeline that includes our partner's 50 percent share of project development costs expensed by Bluegrass Pipeline during the portion of the first quarter of 2014 that Bluegrass Pipeline was consolidated;
- $71 million unfavorable for our investment in ACMP due to the consolidation of ACMP in third quarter 2014;

- $13 million unfavorable for our investment in Cardinal resulting from the consolidation of ACMP in third quarter 2014.

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.

Year-Over-Year Operating Results – Segments

Williams Partners

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Service revenues	$5,135	$3,888	$2,914
Product sales	2,196	$3,521	3,921
Segment revenues	7,331	$7,409	$6,835
Product costs	(1,779)	(3,016)	(3,027)
Other segment costs and expenses	(2,374)	(1,812)	(1,610)
Net insurance recoveries – Geismar Incident	126	232	40
Proportional Modified EBITDA of equity-method investments	699	431	209
Williams Partners Modified EBITDA	$4,003	$3,244	$2,447
NGL margin	$159	$388	$518
Olefin margin	226	110	302

2015 vs. 2014

Modified EBITDA increased primarily due to the acquisition of ACMP during the third quarter of 2014 and increased fee revenue associated with contributions from new and expanded facilities, including Gulfstar One during the fourth quarter 2014, in addition to resuming our Geismar operations and contributions related to the completion of the Keathley Canyon Connector at Discovery. Partially offsetting these increases to Modified EBITDA is a decrease in NGL margins as a result of a significant decline in commodity prices beginning in the fourth quarter of 2014 and lower insurance recoveries related to the Geismar Incident.

The increase in Service revenues is primarily due to $810 million additional revenues associated with a full year of ACMP operations in 2015 which includes a $72 million increase in the minimum volume commitment fees, $223 million in increased revenues associated with the start-up of operations at Gulfstar One during the fourth quarter of 2014, and a $155 million increase in Transco’s natural gas transportation fees due to new projects placed in service in 2015 and 2014. Additionally, service revenues reflect higher fees associated with increased volumes and additional contributions in the Northeast. Higher revenues in the Northeast include expanded gathering operations and processing, fractionation and transportation operations, contributing $59 million and $27 million of additional fees, respectively.

The decrease in Product sales includes:

- A $1,173 million decrease in marketing revenues primarily associated with lower prices across all products, partially offset by higher non-ethane volumes (more than offset in marketing purchases).

- A $324 million decrease in revenues from our equity NGLs reflecting a decrease of $365 million due to lower NGL prices, partially offset by a $41 million increase associated with higher NGL volumes.
- A $41 million decrease in revenues primarily due to lower condensate prices.
- A $214 million increase in olefin sales primarily due to $298 million in higher sales from our Geismar plant that returned to operation, partially offset by a $58 million decrease from our Canadian operations and a $26 million decrease from our RGP Splitter. The decrease in Canada is comprised of $68 million in lower prices, partially offset by $10 million associated with higher propylene volumes. The lower prices reflect a 53 percent per-unit decrease in propylene prices and a 39 percent per-unit decrease in alky feedstock prices. The decrease in sales at our RGP Splitter is caused by $15 million in lower propane sales reflecting 56 percent lower per-unit prices and $11 million in lower propylene sales reflecting 47 percent lower per-unit prices, partially offset by favorable volumes.

The decrease in Product costs includes:

- A $1,219 million decrease in marketing purchases primarily due to a decrease in non-ethane per-unit cost (substantial offset in marketing revenues).
- A $95 million decrease in the natural gas purchases associated with the production of equity NGLs reflecting a decrease of $127 million due to lower natural gas prices, partially offset by a $31 increase associated with higher volumes.
- A $20 million decrease in costs primarily due to lower gas prices.
- A $98 million increase in olefin feedstock purchases is comprised of $127 million in higher purchases due to increased volumes at our Geismar plant as it returned to operation, partially offset by $16 million in lower olefin feedstock purchases in our Canadian operations primarily due to lower per-unit feedstock costs across all products and $13 million in lower costs at our RGP Splitter driven by lower per-unit costs, partially offset by significantly higher volumes in 2015. During 2014, the splitter was running at reduced volumes because a third-party storage facility was down during the first quarter and transportation was limited due to the Geismar Incident.

The increase in Other segment costs and expenses includes:

- An increase for new expenses associated with operations acquired in the ACMP Acquisition.
- The absence of $154 million of cash received in the fourth quarter of 2014 associated with the resolution of a contingent gain related to claims arising from the purchase of a business in a prior period (see Note 6 – Other Income and Expenses of Notes to Consolidated Financial Statements).
- A $94 million impairment charge associated with previously capitalized project development costs for a gas processing plant.
- A $16 million increase in operating expense due to the Geismar plant returning to operation in 2015.
- The absence of a $12 million net gain recognized in 2014 related to a partial acreage dedication release.

The decrease in Net insurance recoveries - Geismar Incident is primarily due to the 2015 receipt of $126 million of insurance proceeds compared to $246 million received in 2014, partially offset by the absence of covered insurable expenses in excess of our retentions (deductibles) related to the Geismar Incident in 2015 compared to $14 million in 2014.

The increase in Proportional Modified EBITDA of equity-method investments is primarily due to a full year contribution of $160 million from investments acquired in the ACMP Acquisition and a $103 million increase from

Discovery associated with higher fee revenues attributable to the completion of the Keathley Canyon Connector in the first quarter of 2015. Additionally, Caiman II increased $21 million resulting from assets placed into service in 2014 and 2015, partially offset by the absence of business interruption insurance proceeds received in the prior year, and an $11 million decrease at Laurel Mountain. The decrease at Laurel Mountain was primarily due to $13 million of impairments and lower gathering fees due to lower gathering rates indexed to natural gas prices, partially offset by 24 percent higher volumes and an increase in our ownership percentage compared to the prior year.

2014 vs. 2013

Modified EBITDA increased primarily due to the acquisition of ACMP during the third quarter of 2014, increased fee revenue associated with contributions from new and expanded facilities, higher insurance recoveries related to the Geismar Incident, and a favorable settlement. Partially offsetting these increases to Modified EBITDA are lower margins as a result of a significant decline in commodity prices beginning in the fourth quarter of 2014 and higher impairment charges related to certain materials and equipment.

The increase in Service revenues is primarily due to a $781 million of increased service revenues associated with operations acquired in the ACMP Acquisition beginning in the third quarter 2014, including $167 million of MVC fees. Additionally, service revenues reflect $88 million higher fee-based revenues resulting from higher gathering volumes driven by new well connections, the completion of various compression projects, and a net increase in gathering rates associated with customer contract modifications primarily in the Susquehanna Supply Hub of the Northeast region. Fee-based revenues also increased $22 million due to contributions from our Ohio Valley Midstream business resulting from the addition of processing, fractionation and transportation facilities placed in service in 2013 and 2014. In addition, natural gas transportation revenues increased $71 million primarily from expansion projects placed into service in 2013 for Transco and $19 million in new service fees associated with the start-up of our Gulfstar One assets.

The decrease in Product sales includes:

- A $251 million decrease in olefin sales primarily associated with a $295 million decrease due to lower volumes related to the lack of production in 2014 as a result of the Geismar Incident, partially offset by a $42 million increase in revenues from our RGP Splitter associated with a $32 million increase in volumes due to a third-party storage facility resuming operations during 2014, and a $10 million increase due to higher per-unit sales prices (substantially offset in Product costs).
- A $132 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $161 million due to lower non-ethane volumes, partially offset by a $29 million increase associated with higher average ethane per-unit sales prices. Equity non-ethane sales volumes are 22 percent lower primarily due to a customer contract that expired in September 2013.
- A $26 million decrease in marketing revenues primarily associated with lower crude oil volumes and prices, and lower non-ethane prices, partially offset by increased non-ethane volumes.

The decrease in Product costs includes:

- A $59 million decrease in olefin feedstock purchases primarily associated with a $99 million decrease due to lower volumes related to the lack of production in 2014 as a result of the Geismar Incident. Offsetting this decrease is a $36 million increase from our RGP Splitter facility attributable to a $30 million increase in volumes due to a third-party storage facility resuming operations during 2014 and a $6 million increase in per-unit costs (more than offset in Product sales).
- A $2 million decrease in natural gas purchases associated with the production of equity NGLs reflecting $87 million associated with lower volumes, which were substantially offset by an $85 million increase associated with higher natural gas prices.

- A $33 million increase in marketing purchases primarily due to increased NGL volumes and lower-of-cost-or-market (LCM) inventory adjustments associated with significant declines in NGL prices during the fourth quarter of 2014.

The increase in Other segment costs and expenses includes:

- A $293 million increase in expenses associated with operations acquired in the ACMP Acquisition. These expenses include Operating and maintenance expenses and Selling, general and administrative expenses (SG&A).
- A $24 million increase in SG&A due to higher legal and arbitration costs, consulting expenses and employee costs.
- A $95 million favorable change in Other (income) expense – net primarily due to $154 million settlement arising from the resolution of a contingent gain related to claims associated with the purchase of a business in a prior period and the absence of a $25 million accrued loss recognized in 2013 associated with a producer claim against us. Partially offsetting these gains are $52 million of impairment charges recognized in 2014 related to certain materials and equipment, a $10 million loss related to the sale of certain assets and a $9 million increase in expenses associated with a regulatory liability for certain employee costs.
- A $13 million benefit related to an increase in equity AFUDC due to higher spending on Constitution and various Transco expansion projects.

The increase in Net insurance recoveries - Geismar Incident is primarily due to the 2014 receipt of $246 million of insurance proceeds compared to $50 million received in 2013, partially offset by $4 million higher covered insurable expenses in excess of our retentions (deductibles) related to the Geismar Incident in 2014 compared to 2013.

The increase in Proportional Modified EBITDA of equity-method investments is primarily due to a $178 million contribution during the second half of 2014 from investments acquired in the ACMP Acquisition. Additionally, Caiman II increased $25 million resulting from assets placed into service in 2014, business interruption insurance proceeds received in 2014 and a higher ownership percentage. Laurel Mountain also increased $12 million due to the absence of certain 2013 write-offs, increased gathering volumes and increased ownership.

Williams NGL & Petchem Services

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Service revenues	$2	$—	$—
Segment costs and expenses	(85)	(37)	(33)
Proportional Modified EBITDA of equity-method investments	—	(78)	—
Williams NGL & Petchem Services Modified EBITDA	$(83)	$(115)	$(33)

2015 vs. 2014

The favorable change in Modified EBITDA is primarily due to the absence of our share of the 2014 write-off of previously capitalized project development costs at Bluegrass Pipeline and Moss Lake, as well as costs incurred in 2014 relating to the development of the Bluegrass Pipeline, partially offset by the 2015 write-off of previously capitalized project development costs for an olefins pipeline project.

Segment costs and expenses increased primarily due to the $64 million write-off of previously capitalized project development costs for an olefins pipeline project in 2015, partially offset by the absence of $18 million of project development costs incurred in 2014 relating to the Bluegrass Pipeline.

The favorable change in Proportional Modified EBITDA of equity-method investments is primarily due to the absence of our share of the 2014 write-off of previously capitalized project development costs at Bluegrass Pipeline and Moss Lake.

2014 vs. 2013

The unfavorable change in Modified EBITDA is primarily due to our share of the 2014 write-off of previously capitalized project development costs at Bluegrass Pipeline and Moss Lake, as well as costs incurred in 2014 relating to the development of the Bluegrass Pipeline, partially offset by the absence of a 2013 write-off of an abandoned project.

Segment costs and expenses increased primarily due to higher expensed costs related to development projects. We expensed $18 million of project development costs during 2014 related to Bluegrass Pipeline. These higher expenses were substantially offset by the absence of a $20 million write-off of an abandoned project during 2013.

The unfavorable change in Proportional Modified EBITDA of equity-method investments is due to losses from Bluegrass Pipeline and Moss Lake related primarily to the underlying write-off of previously capitalized project development costs in 2014.

Other

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Other Modifed EBITDA	$(29)	$103	$197

2015 vs. 2014

Modified EBITDA decreased significantly as the results from the businesses acquired in the ACMP Acquisition are presented within Williams Partners for periods subsequent to the July 1, 2014, acquisition. Other included the proportional Modified EBITDA of $104 million of our former equity-method investment in ACMP for the first half of 2014, which was partially offset by $19 million associated with our share of compensation costs triggered by the ACMP Acquisition recognized in July 2014. Modified EBITDA also decreased by $30 million related to costs incurred in 2015 related to evaluating our strategic alternatives and the Merger Agreement with Energy Transfer, as well as $24 million of higher costs associated with integration and re-alignment of resources following the ACMP Acquisition and Merger. These decreases are partially offset by a $9 million contingency gain settlement recognized in fourth quarter 2015.

2014 vs. 2013

Modified EBITDA decreased significantly as the results from our former equity-method investment in ACMP are included in Other for the first half of 2014, while 2013 included a full year of results. Modified EBITDA also decreased related to $19 million of our share of compensation costs triggered by the ACMP Acquisition incurred in 2014, as previously discussed, and integration and re-alignment of resources following the ACMP Acquisition. These decreases are partially offset by lower expenses incurred related to benefits and higher benefit from the allowance for equity funds used for construction associated with capital projects within our regulated operations.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2015, we continued to focus upon both growth in our businesses through disciplined investment and growth in our per-share dividends. Examples of this growth included:

- Expansion of WPZ's interstate natural gas pipeline system through projects such as Leidy Southeast and Virginia Southside to meet the demand of growth markets;
- WPZ's acquisitions of a gathering system in the Eagle Ford shale and an additional 13 percent interest in its equity-method investment in UEOM;
- WPZ's commissioning of the Bucking Horse gas processing facility joint venture in the Powder River basin Niobrara Shale;
- Total per-share dividends grew 25 percent to $2.45 in 2015 compared to $1.9575 in 2014.

This growth was funded through cash flow from operations, distributions from WPZ, and additional net borrowings at WPZ.

Outlook

We continue to transition to an overall business mix that is increasingly fee-based. Although our cash flows are impacted by fluctuations in energy commodity prices, that impact is somewhat mitigated by certain of our cash flow streams that are not directly impacted by short-term commodity price movements, including:

- Firm demand and capacity reservation transportation revenues under long-term contracts;
- Fee-based revenues from certain gathering and processing services.

However, we are indirectly exposed to longer duration depressed energy commodity prices and the related impact on drilling activities and volumes available for gathering and processing services.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, dividends and distributions, debt service payments, and tax payments, while maintaining a sufficient level of liquidity. In particular, we note that our expected growth capital and investment expenditures total approximately $2.2 billion in 2016, down approximately $1.5 billion from previous plans. Approximately $1.3 billion of our growth capital funding needs include Transco expansions and other interstate pipeline growth projects, most of which are fully contracted with firm transportation agreements. The remaining growth capital and investment expenditures primarily reflect investments in gathering and processing systems limited to known new producer volumes, including wells drilled and completed awaiting connecting infrastructure. 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 retain the flexibility to adjust planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities. In addition, we expect proceeds from planned asset monetizations in excess of $1 billion during 2016.

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 2016. Our internal and external sources of consolidated liquidity to fund working capital requirements, capital and investment expenditures, debt service payments, dividends and distributions, and tax payments include:

- Cash and cash equivalents on hand;

- Cash generated from operations, including cash distributions from WPZ and our equity-method investees based on our level of ownership and incentive distribution rights;
- Cash proceeds from issuances of debt and/or equity securities;
- Use of our credit facility.

WPZ is expected to fund its cash needs through its cash flows from operations and its credit facilities and/or commercial paper program, Transco's recent debt issuance described further below, and planned asset monetizations as previously mentioned. WPZ does not plan to issue public equity or public debt in 2016. We anticipate the more significant uses of cash to be:

- Maintenance and expansion capital and investment expenditures;
- Interest on long-term debt;
- Repayment of current debt maturities;
- Quarterly dividends and distributions.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include those previously discussed in Company Outlook.

As of December 31, 2015, we had a working capital deficit (current liabilities, inclusive of commercial paper outstanding and long-term debt due within one year, in excess of current assets) of $970 million. Excluding the impact of the $499 million in commercial paper outstanding, which we consider to be a reduction of WPZ's credit facility capacity as noted in the table below, our working capital deficit is $471 million. Our available liquidity is as follows:

	December 31, 2015		
Available Liquidity	WPZ	WMB	Total
	(Millions)		
Cash and cash equivalents	$96	$4	$100
Capacity available under our $1.5 billion credit facility (1)		850	850
Capacity available to WPZ under its $3.5 billion credit facility less amounts outstanding under its $3 billion commercial paper program (2)	1,691		1,691
Capacity available to WPZ under its short-term credit facility (3)	150		150
	$1,937	$854	$2,791

(1) The highest amount outstanding under our credit facility during 2015 was $675 million. At December 31, 2015, we were in compliance with the financial covenants associated with this credit facility. See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on our credit facility. Borrowing capacity available under this facility as of February 25, 2016, was $1.025 billion.

(2) In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of WPZ's credit facility inclusive of any outstanding amounts under its commercial paper program. WPZ has $499 million of commercial paper outstanding at December 31, 2015. The highest amount outstanding under WPZ's commercial paper program and credit facility during 2015 was $3.1 billion. At December 31, 2015, WPZ was in compliance with the financial covenants associated with this credit facility and the commercial paper program. See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on WPZ's credit facility and WPZ's commercial paper program. Borrowing capacity available under this facility as of February 25, 2016, was $2.507 billion.

(3) See Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements for additional information on WPZ’s short-term credit facility entered into August 26, 2015, and amended December 23, 2015. Borrowing capacity available under this facility as of February 25, 2016, was $150 million.

On September 24, 2015, WPZ received a special distribution of $396 million from Gulfstream reflecting its proportional share of the proceeds from new debt issued by Gulfstream. The new debt was issued to refinance Gulfstream’s debt maturities. Subsequently, WPZ contributed $248 million to Gulfstream for its proportional share of amounts necessary to fund debt maturities of $500 million due on November 1, 2015. WPZ also expects to contribute its proportional share of amounts necessary to fund debt maturities of $300 million due on June 1, 2016.

As described in Note 14 – Debt, Banking Arrangements, and Leases of Notes to Consolidated Financial Statements, we have determined that we have net assets that are technically considered restricted in accordance with Rule 4-08(e) of Regulation S-X of the Securities and Exchange Commission in excess of 25 percent of our consolidated net assets. We do not expect this determination will impact our ability to pay dividends or meet future obligations as the terms of WPZ’s partnership agreement require it to make quarterly distributions of all available cash, as defined, to its unitholders.

WPZ Incentive Distribution Rights

Our ownership interest in WPZ includes the right to incentive distributions determined in accordance with WPZ’s partnership agreement. We have agreed to temporarily waive incentive distributions of approximately $2 million per quarter in connection with WPZ’s acquisition of an approximate 13 percent additional interest in UEOM on June 10, 2015. The waiver will continue through the quarter ending September 30, 2017.

We are required to pay a $428 million termination fee to WPZ, associated with the Termination Agreement (as described in Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies of Notes to Consolidated Financial Statements), which will settle through a reduction of quarterly incentive distributions we are entitled to receive from WPZ (such reduction not to exceed $209 million per quarter). The November 2015 and February 2016 distributions from WPZ were each reduced by $209 million related to this termination fee.

Debt Issuances and Retirements

On January 22, 2016, Transco issued $1 billion of 7.85 percent senior unsecured notes due 2026 to investors in a private debt placement. Transco intends to use the net proceeds from the offering to repay debt and to fund capital expenditures.

In December 2015, WPZ borrowed $850 million on a variable interest rate loan with certain lenders due 2018. WPZ used the proceeds for working capital, capital expenditures, and for general partnership purposes.

On April 15, 2015, WPZ paid $783 million, including a redemption premium, to retire $750 million of 5.875 percent senior notes due 2021.

On March 3, 2015, WPZ completed a public offering of $1.25 billion of 3.6 percent senior unsecured notes due 2022, $750 million of 4 percent senior unsecured notes due 2025, and $1 billion of 5.1 percent senior unsecured notes due 2045. WPZ used the net proceeds to repay amounts outstanding under its commercial paper program and credit facility, to fund capital expenditures, and for general partnership purposes.

WPZ retired $750 million of 3.8 percent senior unsecured notes that matured on February 15, 2015.

On June 27, 2014, Pre-merger WPZ completed a public offering of $750 million of 3.9 percent senior unsecured notes due 2025 and $500 million of 4.9 percent senior unsecured notes due 2045. Pre-merger WPZ used the net proceeds to repay amounts outstanding under our commercial paper program, to fund capital expenditures, and for general partnership purposes.

On June 24, 2014, we completed a public offering of $1.25 billion of 4.55 percent senior unsecured notes due 2024 and $650 million of 5.75 percent unsecured notes due 2044. We used the net proceeds to finance a portion of the ACMP Acquisition.

On March 4, 2014, Pre-merger WPZ completed a public offering of $1 billion of 4.3 percent senior unsecured notes due 2024 and $500 million of 5.4 percent senior unsecured notes due 2044. Pre-merger WPZ used the net proceeds to repay amounts outstanding under our commercial paper program, to fund capital expenditures, and for general partnership purposes.

Equity Offering

On June 23, 2014, we issued 61 million shares of common stock in a public offering at a price of $57.00 per share. That amount includes 8 million shares purchased pursuant to the full exercise of the underwriter's option to purchase additional shares. The net proceeds of $3.378 billion were used to finance a portion of the ACMP Acquisition.

Shelf Registrations

On May 11, 2015, we filed a shelf registration statement, as a well-known seasoned issuer.

On February 25, 2015, WPZ filed a shelf registration statement, as a well-known seasoned issuer and WPZ also filed a shelf registration statement for the offer and sale from time to time of common units representing limited partner interests in WPZ having an aggregate offering price of up to $1 billion. These sales will be made over a period of time and from time to time in transactions at prices which are market prices prevailing at the time of sale, prices related to market price or at negotiated prices. Such sales will be made pursuant to an equity distribution agreement between WPZ and certain banks who may act as sales agents or purchase for its own accounts as principals. During 2015, 1,790,840 common units were issued under this registration. The net proceeds of $59 million were used for general partnership purposes.

Distributions from Equity-Method Investees

The organizational documents of entities in which we have an equity-method interest 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 5 – Investing Activities of Notes to Consolidated Financial Statements for our more significant equity-method investees.

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. The current ratings are as follows:

	Rating Agency	Outlook	Senior Unsecured Debt Rating	Corporate Credit Rating
WMB:	Standard & Poor's	Stable	BB	BB
	Moody's Investors Service	Ratings Under Review For Downgrade	Ba1	N/A
	Fitch Ratings	Rating Watch Negative	BB+	N/A
WPZ:	Standard & Poor's	Negative	BBB-	BBB-
	Moody's Investors Service	Negative	Baa3	N/A
	Fitch Ratings	Stable	BBB-	N/A

During January 2016 Moody's Investors Service and Fitch Ratings downgraded the rating for WMB below investment grade and Standard & Poor's revised the WMB outlook. As a result, WMB's future cost of borrowings could increase. As of December 31, 2015, we estimate that we could be required to provide up to $235 million in additional collateral of either cash or letters of credit with third parties under existing contracts. At the present time, we have not provided any additional collateral to third parties but no assurance can be given that we will not be requested to provide collateral in the future. The credit ratings agencies lowered the ratings of WPZ in December 2015 and in January 2016, and Standard & Poor's and Fitch Ratings revised the WPZ outlook. In February 2016, Standard & Poor's affirmed WPZ's ratings and revised WPZ's outlook. WPZ maintains investment grade ratings. As of December 31,

2015, we estimate that a downgrade to a rating below investment grade for WPZ could require it to provide up to $271 million in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Net cash provided (used) by:			
Operating activities	$2,678	$2,115	$2,217
Financing activities	481	7,601	1,677
Investing activities	(3,299)	(10,157)	(4,052)
Increase (decrease) in cash and cash equivalents	$(140)	$(441)	$(158)

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 Impairment of goodwill, Gain on remeasurement of equity-method investment, Impairment of equity-method investments, Depreciation and amortization, and Provision (benefit) for deferred income taxes. Our Net cash provided (used) by operating activities in 2015 increased from 2014 primarily due to the impact of net favorable changes in operating working capital and the absence of contributions from ACMP for the first six months of 2014.

Our Net cash provided (used) by operating activities in 2014 decreased from 2013 primarily due to the impact of net unfavorable changes in operating working capital, lower olefins production margins, and increased interest payments on debt. These changes were partially offset by proceeds from insurance recoveries on the Geismar Incident, proceeds from a contingency settlement in 2014, and contributions from consolidating ACMP for the second half of 2014.

Financing activities

Significant transactions include:

2015

- $306 million of net payments of WPZ’s commercial paper;
- $3.842 billion net received from WPZ’s debt offerings;
- $1.533 billion paid on WPZ’s debt retirements;
- $2.097 billion received from our credit facility borrowings;
- $1.817 billion paid on our credit facility borrowings;
- $3.832 billion received from WPZ’s credit facility borrowings;
- $3.162 billion paid on WPZ’s credit facility borrowings;
- $1.836 billion paid for quarterly dividends on common stock;
- $942 million paid for dividends and distributions to noncontrolling interests;
- $111 million received in contributions from noncontrolling interests;
- $396 million special distribution from Gulfstream;

- $248 million contribution to Gulfstream for repayment of debt.

2014

- $572 million net proceeds received from WPZ’s commercial paper issuances;
- $1.895 billion net received from our debt offerings;
- $2.74 billion net proceeds received from WPZ’s debt offerings;
- $670 million paid on our credit facility borrowings;
- $1.040 billion received from our credit facility borrowings;
- $1.646 billion received from WPZ’s credit facility borrowings;
- $1.156 billion paid on WPZ’s credit facility borrowings;
- $3.416 billion received from our equity offerings;
- $1.412 billion paid for quarterly dividends on common stock;
- $840 million paid for dividends and distributions to noncontrolling interests;
- $340 million received in contributions from noncontrolling interests.

2013

- $224 million net proceeds received from WPZ’s commercial paper issuances;
- $994 million net proceeds received from WPZ’s November 2013 public offering of $600 million of 4.5 percent senior unsecured notes due 2023 and $400 million of 5.8 percent senior unsecured notes due 2043;
- $1.705 billion received from WPZ’s credit facility borrowings;
- $2.08 billion paid on WPZ’s credit facility borrowings;
- $1.819 billion received from WPZ’s equity offerings;
- $982 million paid for quarterly dividends on common stock;
- $489 million paid for dividends and distributions to noncontrolling interests;
- $467 million received in contributions from noncontrolling interests.

Investing activities

Significant transactions include:

2015

- Capital expenditures totaled $3.167 billion;
- $112 million paid to purchase a gathering system comprised of approximately 140 miles of pipeline and a sour gas compression facility in the Eagle Ford shale;

- Purchases of and contributions to our equity-method investments of $595 million;

2014

- Capital expenditures totaled $4.031 billion;
- Purchases of and contributions to our equity-method investments of $482 million;
- $5.958 billion paid, net of cash acquired, for the ACMP Acquisition.

2013

- Capital expenditures totaled $3.572 billion;
- Purchases of and contributions to our equity-method investments of $455 million.

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

We have various other guarantees and commitments which are disclosed in Note 3 – Variable Interest Entities, Note 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, 2015:

	2016	2017 - 2018	2019 - 2020	Thereafter	Total
			(Millions)		
Long-term debt: (1)					
Principal (2)	$375	$2,135	$4,113	$17,377	$24,000
Interest	1,078	2,016	1,890	8,454	13,438
Commercial paper	499	—	—	—	499
Capital leases	1	—	—	—	1
Operating leases	95	130	84	119	428
Purchase obligations (3)	1,414	365	292	347	2,418
Other obligations (4)(5)	2	2	1	3	8
Total	$3,464	$4,648	$6,380	$26,300	$40,792

____

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

(2) The 2016 amount includes $200 million that is presented as long-term debt at December 31, 2015 on the Consolidated Balance Sheet, due to WPZ’s intent and ability to refinance.

(3) Includes approximately $730 million in open property, plant, and equipment purchase orders. Includes an estimated $269 million long-term ethane purchase obligation with index-based pricing terms that is reflected in this table at December 31, 2015 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 resold at comparable prices in the Mont Belvieu market. Includes an estimated $411 million long-term NGL purchase obligation with index-based pricing terms that primarily supplies a third party at its plant and is valued in this table at a price calculated using December 31, 2015 prices. Any excess purchased volumes may be sold at comparable market 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.)

(4) 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 $70 million in 2015 and $69 million in 2014. In 2016, we expect to contribute approximately $69 million to these plans (see Note 9 – 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 2015, we contributed $60 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 2016, 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.

(5) We have not included income tax liabilities in the table above. See Note 7 – 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 36 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 $40 million, all of which are included in Accrued liabilities and Other noncurrent liabilities on the Consolidated Balance Sheet at December 31, 2015. We will seek recovery of approximately $8 million of these accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2015, we paid approximately $7 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $7 million in 2016 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, 2015, 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.

In March 2008, the EPA promulgated a new, lower National Ambient Air Quality Standard (NAAQS) for ground-level ozone. In May 2012, the EPA completed designation of new eight-hour ozone nonattainment areas. Several Transco facilities are located in 2008 ozone nonattainment areas. In December 2014, the EPA proposed to further reduce the ground-level ozone NAAQS from the March 2008 levels and subsequently finalized a rule on October 1, 2015. We are monitoring the rule's implementation as the reduction will trigger additional federal and state regulatory actions that may impact our operations. To date, no federal actions have been proposed to mandate additional emission controls at these facilities. Pursuant to pending state regulatory actions associated with implementation of the 2008 ozone standard, we anticipate that some facilities may be subject to increased controls within five years. 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 on the Consolidated Balance Sheet for both new and existing facilities in affected areas. We are unable at this time to estimate with any certainty the cost of additions that may be required to meet the regulations.

On January 22, 2010, the EPA set a new one-hour nitrogen dioxide (NO2) NAAQS. The effective date of the new NO2 standard was April 12, 2010. On January 20, 2012, the EPA determined pursuant to available information that no area in the country is violating the 2010 NO2 NAAQS and thus designated all areas of the country as "unclassifiable/attainment." Also, at that time the EPA noted its plan to deploy an expanded NO2 monitoring network beginning in 2013. However on October 5, 2012, the EPA proposed a graduated implementation of the monitoring network between January 1, 2014 and January 1, 2017. Once three years of data is collected from the new monitoring network, the EPA will reassess attainment status with the one-hour NO2 NAAQS. Until that time, the EPA or states may require ambient air quality modeling on a case by case basis to demonstrate compliance with the NO2 standard. Because we are unable to predict the outcome of the EPA's or states' future assessment using the new monitoring network, we are unable to estimate the cost of additions that may be required to meet this regulation.

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.

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 the credit facilities and any issuances under WPZ's 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, 2015 and 2014. Long-term debt in the tables represents principal cash flows, net of (discount) premium and debt issuance costs, and weighted-average interest rates by expected maturity dates. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings.

	2016	2017	2018	2019	2020	Thereafter (1)	Total	Fair Value December 31, 2015
	(Millions)							
Long-term debt, including current portion: (2)								
Fixed rate	$ 375 (*)	$ 785	$ 500	$ 32	$ 2,121	$ 17,364	$ 21,177	$ 16,796
Interest rate	5.1 %	5.1 %	5.0 %	5.0 %	5.0 %	5.5 %		
Variable rate	$ —	$ —	$ 850	$ —	$ 1,960	$ —	$ 2,810	$ 2,810
Interest rate (3)								
Commercial paper:								
Variable rate	$ 499	$ —	$ —	$ —	$ —	$ —	$ 499	$ 499
Interest rate (4)								

(*) $200 million presented as long-term debt at December 31, 2015, due to WPZ's intent and ability to refinance.

	2015	2016	2017	2018	2019	Thereafter (1)	Total	Fair Value December 31, 2014
	(Millions)							
Long-term debt, including current portion: (2)								
Fixed rate	$ 750 (**)	$ 375	$ 785	$ 500	$ 32	$ 17,327	$ 19,769	$ 20,121
Interest rate	5.2 %	5.3 %	5.2 %	5.2 %	5.1 %	5.4 %		
Variable rate	$ —	$ —	$ —	$ 1,010	$ —	$ —	$ 1,010	$ 1,010
Interest rate (5)								
Commercial paper:								
Variable rate	$ 798	$ —	$ —	$ —	$ —	$ —	$ 798	$ 798
Interest rate (4)								

(**) Presented as long-term debt at December 31, 2014, due to WPZ's intent and ability to refinance.

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

(2) Excludes capital leases.

(3) The weighted-average interest rates for WPZ’s $1.3 billion credit facility borrowing, WPZ’s $850 million term loan, and our $650 million credit facility borrowing at December 31, 2015 were 1.63 percent, 1.85 percent, and 2.32 percent, respectively.

(4) The weighted-average interest rate was 0.92 percent at both December 31, 2015 and 2014.

(5) The weighted-average interest rates for WPZ's $640 million and our $370 million credit facility borrowings at December 31, 2014 were 2.42 percent and 1.67 percent, respectively.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs, olefins, 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 a conservative capital structure and 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, 2015 and 2014, our derivative activity was not material. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk of Notes to Consolidated Financial Statements.)

Foreign Currency Risk

Our foreign operations, whose functional currency is the local currency, are located in Canada. Net assets of our foreign operations were approximately $1.4 billion and $1.3 billion at December 31, 2015 and 2014, respectively. These investments have the potential to impact our financial position due to fluctuations in the local currency arising from the process of translating the local functional currency into the U.S. dollar. As an example, a 20 percent change in the functional currency against the U.S. dollar would have changed Total stockholders' equity by approximately $179 million and approximately $157 million at December 31, 2015 and 2014, respectively.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2015 and 2014, 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, 2015. Our audits also included the financial statement schedules listed in the index at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits. 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) or, prior to 2014, the consolidated financial statements of Access Midstream Partners, L.P. (“ACMP”) (a master limited partnership in which the Company acquired a 50 percent general partner interest and a 23 percent limited partner interest in December 2012 and the remaining 50 percent general partner interest and an additional 27 percent limited partner interest in July 2014). In the consolidated financial statements, the Company’s investment in Gulfstream was $293 million as of December 31, 2015, and the Company’s equity earnings in the net income of Gulfstream were $65 million and $67 million, respectively, for the years ended December 31, 2015 and 2013. In the consolidated financial statements, the Company’s equity earnings in the net income of ACMP was $93 million for the year ended December 31, 2013. For the periods indicated above, Gulfstream’s and ACMP’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 for 2015 and 2013 and ACMP for 2013, is based solely on the reports of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and, for 2015 and 2013 for Gulfstream and for 2013 for ACMP, the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2015, 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 26, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of Gulfstream Natural Gas System, L.L. C.
We have audited the balance sheets of Gulfstream Natural Gas System, L.L.C. as of December 31, 2015 and 2014, and the related statements of operations, comprehensive income, members’ equity, and cash flows for each of the three years in the period ended December 31, 2015. 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 audits.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 audits 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 audits provide a reasonable basis for our opinion.
In our opinion, such financial statements present fairly, in all material respects, the financial position of Gulfstream Natural Gas System, L.L.C. as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Access Midstream Partners GP, L.L.C., as General Partner of Williams Partners, L.P. formerly known as Access Midstream Partners, L.P. and the Unitholders

In our opinion, the consolidated statement of income, of changes in partners' capital and of cash flows for the year ended December 31, 2013, present fairly, in all material respects, the results of operations and cash flows of Williams Partners L.P. (formerly known as Access Midstream Partners, L.P.) and its subsidiaries (the "Partnership") in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 21, 2014, except for Note 16 to the consolidated financial statements appearing under Item 8 of the Partnership's 2013 Annual Report on Form 10-K/A (not presented herein), as to which the date is March 3, 2014, and except for the effects of the capital structure change described in Note 1 to the consolidated financial statements appearing under Item 8 of the Partnership's 2014 Annual Report on Form 10-K (not presented herein), as to which the date is February 25, 2015

The Williams Companies, Inc.
Consolidated Statement of Operations

	Years Ended December 31,		
	2015	2014	2013
	(Millions, except per-share amounts)		
Revenues:			
Service revenues	$5,164	$4,116	$2,939
Product sales	2,196	3,521	3,921
Total revenues	7,360	7,637	6,860
Costs and expenses:			
Product costs	1,779	3,016	3,027
Operating and maintenance expenses	1,655	1,492	1,097
Depreciation and amortization expenses	1,738	1,176	815
Selling, general, and administrative expenses	741	661	512
Impairment of goodwill	1,098	—	—
Net insurance recoveries – Geismar Incident	(126)	(232)	(40)
Other (income) expense – net	249	(45)	74
Total costs and expenses	7,134	6,068	5,485
Operating income (loss)	226	1,569	1,375
Equity earnings (losses)	335	144	134
Gain on remeasurement of equity-method investment	—	2,544	—
Impairment of equity-method investments	(1,359)	—	—
Other investing income (loss) – net	27	43	81
Interest incurred	(1,118)	(888)	(611)
Interest capitalized	74	141	101
Other income (expense) – net	102	31	—
Income (loss) from continuing operations before income taxes	(1,713)	3,584	1,080
Provision (benefit) for income taxes	(399)	1,249	401
Income (loss) from continuing operations	(1,314)	2,335	679
Income (loss) from discontinued operations	—	4	(11)
Net income (loss)	(1,314)	2,339	668
Less: Net income (loss) attributable to noncontrolling interests	(743)	225	238
Net income (loss) attributable to The Williams Companies, Inc.	$(571)	$2,114	$430
Amounts attributable to The Williams Companies, Inc.:			
Income (loss) from continuing operations	$(571)	$2,110	$441
Income (loss) from discontinued operations	—	4	(11)
Net income (loss)	$(571)	$2,114	$430
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$(.76)	$2.93	$.65
Income (loss) from discontinued operations	—	.01	(.02)
Net income (loss)	$(.76)	$2.94	$.63
Weighted-average shares (thousands)	749,271	719,325	682,948
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$(.76)	$2.91	$.64
Income (loss) from discontinued operations	—	.01	(.02)
Net income (loss)	$(.76)	$2.92	$.62
Weighted-average shares (thousands)	749,271	723,641	687,185

See accompanying notes.

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Net income (loss)	$(1,314)	$2,339	$668
Other comprehensive income (loss):			
Cash flow hedging activities:			
Net unrealized gain (loss) from derivative instruments, net of taxes	6	—	1
Reclassifications into earnings of net derivative instruments (gain) loss, net of taxes of $1 in 2015	(6)	—	(1)
Foreign currency translation adjustments, net of taxes of $31, $18, and $24 in 2015, 2014, and 2013, respectively	(204)	(96)	(41)
Pension and other postretirement benefits:			
Prior service credit (cost) arising during the year, net of taxes of ($9) in 2013 (Note 9)	—	(1)	14
Amortization of prior service cost (credit) included in net periodic benefit cost, net of taxes of $3, $3, and $1 in 2015, 2014, and 2013, respectively	(3)	(5)	(2)
Net actuarial gain (loss) arising during the year, net of taxes of ($5), $60, and ($111) in 2015, 2014, and 2013, respectively (Note 9)	8	(100)	189
Amortization of actuarial (gain) loss included in net periodic benefit cost, net of taxes of ($18), ($15), and ($23) in 2015, 2014, and 2013, respectively	28	26	38
Other comprehensive income (loss)	(171)	(176)	198
Comprehensive income (loss)	(1,485)	2,163	866
Less: Comprehensive income (loss) attributable to noncontrolling interests	(813)	206	238
Comprehensive income (loss) attributable to The Williams Companies, Inc.	$(672)	$1,957	$628

See accompanying notes.

87

The Williams Companies, Inc.
Consolidated Balance Sheet

	December 31, 2015	2014
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$100	$240
Accounts and notes receivable (net of allowance of $3 at December 31, 2015 and $0 at December 31, 2014):		
Trade and other	1,034	972
Income tax receivable	7	167
Deferred income tax assets	42	67
Inventories	127	231
Other current assets and deferred charges	217	213
Total current assets	1,527	1,890
Investments	7,336	8,400
Property, plant, and equipment – net	29,579	28,081
Goodwill	47	1,120
Other intangible assets – net of accumulated amortization	9,970	10,453
Regulatory assets, deferred charges, and other	561	511
Total assets	$49,020	$50,455
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$744	$865
Accrued liabilities	1,078	900
Commercial paper	499	798
Long-term debt due within one year	176	4
Total current liabilities	2,497	2,567
Long-term debt	23,812	20,780
Deferred income tax liabilities	4,218	4,712
Other noncurrent liabilities	2,268	2,224
Contingent liabilities and commitments (Note 18)		
Equity:		
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 784 million shares issued at December 31, 2015 and 782 million shares issued at December 31, 2014)	784	782
Capital in excess of par value	14,807	14,925
Retained deficit	(7,960)	(5,548)
Accumulated other comprehensive income (loss)	(442)	(341)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	6,148	8,777

Noncontrolling interests in consolidated subsidiaries	10,077	11,395
Total equity	16,225	20,172
Total liabilities and equity	$49,020	$50,455

See accompanying notes.

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

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Deficit	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interests	Total Equity
	(Millions)							
Balance – December 31, 2012	$716	$11,134	$(5,695)	$ (362)	$(1,041)	$ 4,752	$ 2,675	$7,427
Net income (loss)	—	—	430	—	—	430	238	668
Other comprehensive income (loss)	—	—	—	198	—	198	—	198
Cash dividends – common stock (Note 15)	—	—	(982)	—	—	(982)	—	(982)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(489)	(489)
Issuance of common stock from debentures conversion	—	1	—	—	—	1	—	1
Stock-based compensation and related common stock issuances, net of tax	2	54	—	—	—	56	—	56
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	1,819	1,819
Changes in ownership of consolidated subsidiaries, net	—	409	—	—	—	409	(652)	(243)
Contributions from noncontrolling interests	—	—	—	—	—	—	467	467
Other	—	1	(1)	—	—	—	(1)	(1)
Net increase (decrease) in equity	2	465	(553)	198	—	112	1,382	1,494
Balance – December 31, 2013	718	11,599	(6,248)	(164)	(1,041)	4,864	4,057	8,921
Net income (loss)	—	—	2,114	—	—	2,114	225	2,339
Other comprehensive income (loss)	—	—	—	(157)	—	(157)	(19)	(176)
Issuance of common stock for acquisition of business (Note 15)	61	3,317	—	—	—	3,378	—	3,378
Noncontrolling interest resulting from acquisition of business (Note 2)	—	—	—	—	—	—	7,502	7,502

Cash dividends – common stock (Note 15)	—	—	(1,412)	—	—	(1,412)	—	(1,412)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(840)	(840)
Stock-based compensation and related common stock issuances, net of tax	3	85	—	—	—	88	—	88
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	55	55
Changes in ownership of consolidated subsidiaries, net	—	(73)	—	(20)	—	(93)	137	44
Contributions from noncontrolling interests	—	—	—	—	—	—	340	340
Deconsolidation of Bluegrass Pipeline (Note 5)	—	—	—	—	—	—	(63)	(63)
Other	—	(3)	(2)	—	—	(5)	1	(4)
Net increase (decrease) in equity	64	3,326	700	(177)	—	3,913	7,338	11,251
Balance – December 31, 2014	782	14,925	(5,548)	(341)	(1,041)	8,777	11,395	20,172
Net income (loss)	—	—	(571)	—	—	(571)	(743)	(1,314)
Other comprehensive income (loss)	—	—	—	(101)	—	(101)	(70)	(171)
Cash dividends – common stock (Note 15)	—	—	(1,836)	—	—	(1,836)	—	(1,836)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(942)	(942)
Stock-based compensation and related common stock issuances, net of tax	2	28	—	—	—	30	—	30
Sales of limited partner units of Williams Partners L.P.	—	—	—	—	—	—	59	59
Changes in ownership of consolidated subsidiaries, net	—	(160)	—	—	—	(160)	254	94
Contributions from noncontrolling interests	—	—	—	—	—	—	111	111
Other	—	14	(5)	—	—	9	13	22
Net increase (decrease) in equity	2	(118)	(2,412)	(101)	—	(2,629)	(1,318)	(3,947)
Balance – December 31, 2015	$784	$14,807	$(7,960)	$ (442)	$(1,041)	$6,148	$ 10,077	$16,225

See accompanying notes.

89

The Williams Companies, Inc.
Consolidated Statement of Cash Flows

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$(1,314)	$2,339	$668
Adjustments to reconcile to net cash provided (used) by operating activities:			
Depreciation and amortization	1,738	1,176	815
Provision (benefit) for deferred income taxes	(337)	1,264	424
Impairment of goodwill	1,098	—	—
Impairment of equity-method investments	1,359	—	—
Impairment of and net (gain) loss on sale of Property, plant, and equipment	215	67	29
Amortization of stock-based awards	82	53	37
Gain on remeasurement of equity-method investment	—	(2,544)	—
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	39	(276)	35
Inventories	105	(36)	(17)
Other current assets and deferred charges	4	(44)	25
Accounts payable	(90)	(8)	(35)
Accrued liabilities	26	(203)	175
Other, including changes in noncurrent assets and liabilities	(247)	327	61
Net cash provided (used) by operating activities	2,678	2,115	2,217
FINANCING ACTIVITIES:			
Proceeds from (payments of) commercial paper – net	(306)	572	224
Proceeds from long-term debt	9,772	7,321	2,699
Payments of long-term debt	(6,516)	(1,828)	(2,081)
Proceeds from issuance of common stock	27	3,416	18
Proceeds from sale of limited partner units of consolidated partnership	59	55	1,819
Dividends paid	(1,836)	(1,412)	(982)
Dividends and distributions paid to noncontrolling interests	(942)	(840)	(489)
Contributions from noncontrolling interests	111	340	467
Payments for debt issuance costs	(35)	(40)	(15)
Special distribution from Gulfstream	396	—	—
Contribution to Gulfstream for repayment of debt	(248)	—	—
Other – net	(1)	17	17
Net cash provided (used) by financing activities	481	7,601	1,677
INVESTING ACTIVITIES:			
Property, plant, and equipment:			
Capital expenditures (1)	(3,167)	(4,031)	(3,572)
Net proceeds from dispositions	3	34	3
Purchases of businesses, net of cash acquired	(112)	(5,958)	(6)
Purchases of and contributions to equity-method investments	(595)	(482)	(455)
Other – net	572	280	(22)
Net cash provided (used) by investing activities	(3,299)	(10,157)	(4,052)
Increase (decrease) in cash and cash equivalents	(140)	(441)	(158)
Cash and cash equivalents at beginning of year	240	681	839
Cash and cash equivalents at end of year	$100	$240	$681

---

(1) Increases to property, plant, and equipment	$(3,024)	$(3,916)	$(3,653)

Changes in related accounts payable and accrued liabilities	(143)	(115)	81
Capital expenditures	$(3,167)	$(4,031)	$(3,572)

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.

Energy Transfer Merger Agreement

On September 28, 2015, we entered into an Agreement and Plan of Merger (Merger Agreement) with Energy Transfer Equity, L.P. (Energy Transfer) and certain of its affiliates. The Merger Agreement provides that, subject to the satisfaction of customary closing conditions, we will be merged with and into the newly formed Energy Transfer Corp LP (ETC) (ETC Merger), with ETC surviving the ETC Merger. Energy Transfer formed ETC as a limited partnership that will be treated as a corporation for U.S. federal income tax purposes. Upon completion of the ETC Merger, ETC will be publicly traded on the New York Stock Exchange under the symbol "ETC."

At the effective time of the ETC Merger, each issued and outstanding share of our common stock (except for certain shares such as those held by us or our subsidiaries and any held by ETC and its affiliates) will be canceled and automatically converted into the right to receive, at the election of each holder and subject to proration as set forth in the Merger Agreement (collectively Merger Consideration):

- 1.8716 common shares representing limited partnership interests in ETC (ETC common shares) (Stock Consideration); or
- $43.50 in cash (Cash Consideration); or
- $8.00 in cash and 1.5274 ETC common shares (Mixed Consideration).

Elections to receive the Stock Consideration or the Cash Consideration will be subject to proration to ensure that the aggregate number of ETC common shares and the aggregate amount of cash paid in the ETC Merger will be the same as if all electing shares of our common stock received the Mixed Consideration. In addition, our stockholders will receive a special one-time dividend of $0.10 per share of Williams common stock, to be paid to holder of record immediately prior to the closing of the ETC Merger and contingent upon consummation of the ETC Merger.

In connection with the ETC Merger, Energy Transfer will subscribe for a number of ETC common shares at the transaction price, in exchange for the amount of cash needed by ETC to fund the cash portion of the Merger Consideration (the Parent Cash Deposit), and, as a result, based on the number of shares of Williams common stock outstanding as of the date thereof, will own approximately 19 percent of the outstanding ETC common shares immediately after the effective time of the ETC Merger.

Immediately following the completion of the ETC Merger and of the LE GP, LLC (the general partner for Energy Transfer) merger with and into Energy Transfer Equity GP, LLC, ETC will contribute to Energy Transfer all of the assets and liabilities of Williams in exchange for the issuance by Energy Transfer to ETC of a number of Energy Transfer Class E common units equal to the number of ETC common shares issued to our stockholders in the ETC Merger plus the number of ETC common shares issued to Energy Transfer in consideration for the Parent Cash Deposit (such contribution, together with the ETC Merger and the other transactions contemplated by the Merger Agreement, the Merger Transactions).

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

To address potential uncertainty as to how the newly listed ETC common shares, as a new security, will trade relative to Energy Transfer common units, each ETC common share issued in the ETC Merger, as well as the ETC common shares issued to Energy Transfer in connection with the Parent Cash Deposit, will have attached to it one contingent consideration right (CCR). The terms of the CCRs are fully described in the form of CCR Agreement attached to the Merger Agreement as Exhibit H to Exhibit 2.1 of our Form 8-K dated September 29, 2015.

The receipt of the Merger Consideration is expected to be tax-free to our stockholders, except with respect to any cash consideration received.

Completion of the Merger Transactions is subject to the satisfaction or waiver of a number of customary closing conditions as set forth in the Merger Agreement, including approval of the ETC Merger by our stockholders, receipt of required regulatory approvals in connection with the Merger Transactions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and effectiveness of a registration statement on Form S-4 registering the ETC common shares (and attached CCRs) to be issued in connection with the Merger Transactions.

ETC filed its initial Form S-4 registration statement on November 24, 2015, and Amendment No. 1 to Form S-4 on January 12, 2016. On December 14, 2015, we and Energy Transfer issued a joint press release announcing the entry into a timing agreement with the United States Federal Trade Commission (FTC) pursuant to which both parties have agreed not to consummate ETC's proposed acquisition of us until after the later of (i) 60 days after substantial compliance with the FTC's request for additional information and documentary material and (ii) March 18, 2016.

Termination of WPZ Merger Agreement

On May 12, 2015, we entered into an agreement for a unit-for-stock transaction whereby we would have acquired all of the publicly held outstanding common units of WPZ in exchange for shares of our common stock (WPZ Merger Agreement).

On September 28, 2015, prior to our entry into the Merger Agreement, we entered into a Termination Agreement and Release (Termination Agreement), terminating the WPZ Merger Agreement. Under the terms of the Termination Agreement, we are required to pay a $428 million termination fee to WPZ, of which we currently own approximately 60 percent, including the interests of the general partner and incentive distribution rights (IDRs). Such termination fee will settle through a reduction of quarterly incentive distributions we are entitled to receive from WPZ (such reduction not to exceed $209 million per quarter). The distributions from WPZ in November 2015 and February 2016 were each reduced by $209 million related to this termination fee.

ACMP Merger

On February 2, 2015, we completed the merger of our consolidated master limited partnerships, Williams Partners L.P. (Pre-merger WPZ) and Access Midstream Partners, L.P. (ACMP) (ACMP Merger). The merged partnership is named Williams Partners L.P. Under the terms of the merger agreement, each ACMP unitholder received 1.06152 ACMP units for each ACMP unit owned immediately prior to the ACMP Merger. In conjunction with the ACMP Merger, each Pre-merger WPZ common unit held by the public was exchanged for 0.86672 ACMP common units. Each Pre-merger WPZ common unit held by us was exchanged for 0.80036 ACMP common units. Prior to the closing of the ACMP Merger, the Class D limited partner units of Pre-merger WPZ, all of which were held by us, were converted into common units on a one-for-one basis pursuant to the terms of the Pre-merger WPZ partnership agreement. Following the ACMP Merger, we own approximately 60 percent of the merged partnership, including the general partner interest and IDRs. In this report, we refer to the post-merger partnership as "WPZ" and the pre-merger entities as "Pre-merger WPZ" and "ACMP."

Description of Business

We are a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. Our operations are located principally in the United States and are organized into the Williams Partners and Williams NGL &

92

Petchem Services reportable segments. All remaining business activities are included in Other. For periods after the ACMP Acquisition (See Note 2 – Acquisitions), the acquired ACMP business is reported within Williams Partners. For periods prior to the ACMP Acquisition, the results associated with our former equity-method investment in ACMP are reported within Other.

Williams Partners

Williams Partners consists of our consolidated master limited partnership, WPZ, and primarily includes gas pipeline and midstream businesses.

WPZ's gas pipeline businesses primarily consist of two interstate natural gas pipelines, which are Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline LLC (Northwest Pipeline), and several joint venture investments in interstate and intrastate natural gas pipeline systems, including a 50 percent equity-method investment in Gulfstream Natural Gas System, L.L.C. (Gulfstream), and a 41 percent interest in Constitution Pipeline Company, LLC (Constitution) (a consolidated entity), which is under development.

WPZ's midstream businesses primarily consist of (1) natural gas gathering, treating, compression, and processing; (2) natural gas liquid (NGL) fractionation, storage, and transportation; (3) crude oil production handling and transportation; and (4) olefins production. The primary service areas are concentrated in major producing basins in Colorado, Texas, Oklahoma, Kansas, New Mexico, Wyoming, the Gulf of Mexico, Louisiana, Pennsylvania, West Virginia, New York, and Ohio which include the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica shale plays as well as the Mid-Continent region.

The midstream businesses include equity-method investments in natural gas gathering and processing assets and NGL fractionation and transportation assets, including a 62 percent equity-method investment in Utica East Ohio Midstream, LLC (UEOM), a 50 percent equity-method investment in the Delaware basin gas gathering system in the Mid-Continent region, 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), a 60 percent equity-method investment in Discovery Producer Services, LLC (Discovery), a 50 percent equity-method investment in Overland Pass Pipeline, LLC (OPPL), and Appalachia Midstream Services, LLC, which owns equity-method investments with an approximate average 45 percent interest in multiple gathering systems in the Marcellus Shale (Appalachia Midstream Investments).

The midstream businesses also include our Canadian midstream operations, which are comprised of an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta.

Williams NGL & Petchem Services

Williams NGL & Petchem Services includes certain other domestic olefins pipeline assets and certain Canadian growth projects under development (including a propane dehydrogenation facility and a liquids extraction plant).

Other

Other includes other business activities that are not operating segments, as well as corporate operations.

Basis of Presentation

Canada Dropdown

In February 2014, we contributed certain Canadian operations to Pre-merger WPZ (Canada Dropdown) for total consideration of $56 million of cash from Pre-merger WPZ (including a $31 million post-closing adjustment received in the second quarter of 2014), 25,577,521 Pre-merger WPZ Class D limited-partner units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. In lieu of cash distributions, the Class D units received quarterly distributions of additional paid-in-kind Class D units.

93

In October 2014, a purchase price adjustment was finalized whereby we paid $56 million in cash to Pre-merger WPZ in the fourth quarter and waived $2 million in payment of IDRs with respect to the November 2014 distribution.

Consolidated master limited partnership

During the fourth quarter of 2015, WPZ issued 1,790,840 common units pursuant to an equity distribution agreement between WPZ and certain banks. Considering this, as well as WPZ's quarterly distribution of additional paid-in-kind Class B units to us, we own approximately 60 percent of the interests in WPZ, including the interests of the general partner, which are wholly owned by us, and IDRs as of December 31, 2015.

The previously described ACMP Merger and other equity issuances by WPZ had the combined net impact of increasing Noncontrolling interests in consolidated subsidiaries by $254 million, and decreasing Capital in excess of par value by $160 million and Deferred income tax liabilities by $94 million in the Consolidated Balance Sheet.

WPZ is self-funding and maintains separate lines of bank credit and cash management accounts and also has a commercial paper program. (See Note 14 – Debt, Banking Arrangements, and Leases.) Cash distributions from WPZ to us, including any associated with our IDRs, occur through the normal partnership distributions from WPZ to all partners.

Discontinued operations

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

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. Management's 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 management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions include:

- Impairment assessments of investments, property, plant, and equipment, goodwill, and other identifiable intangible assets;
- Litigation-related contingencies;
- Environmental remediation obligations;
- Realization of deferred income tax assets;
- Depreciation and/or amortization of equity-method investment basis differences;
- Asset retirement obligations;
- Pension and postretirement valuation variables;
- Acquisition related purchase price allocations.

These estimates are discussed further throughout these notes.

Regulatory accounting

Transco and Northwest Pipeline are regulated by the Federal Energy Regulatory Commission (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, our management has determined that it is appropriate under Accounting Standards Codification (ASC) Topic 980, “Regulated Operations,” 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 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 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, and pension and other postretirement benefits. Our current and noncurrent regulatory asset and liability balances for the years ended December 31, 2015 and 2014 are as follows:

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

	December 31, 2015	2014
	(Millions)	
Current assets reported within Other current assets and deferred charges	$84	$81
Noncurrent assets reported within Regulatory assets, deferred charges, and other	370	337
Total regulated assets	$454	$418
Current liabilities reported within Accrued liabilities	$4	$11
Noncurrent liabilities reported within Other noncurrent liabilities	434	375
Total regulated liabilities	$438	$386

Cash and cash equivalents

Cash and cash equivalents in the Consolidated Balance Sheet includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates 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 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.

Inventory valuation

All Inventories in the Consolidated Balance Sheet are stated at the lower of cost or market. The cost of inventories is primarily determined using the average-cost method.

Property, plant, and equipment

Property, plant, and equipment is 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 asset retirement obligation (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 management expects 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.

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

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.

Goodwill

Goodwill in the Consolidated Balance Sheet represents the excess of the consideration plus the fair value of any noncontrolling interest or any previously held equity interest, over the fair value of the net assets acquired. It is not subject to amortization but is evaluated annually as of October 1 for impairment or more frequently if impairment indicators are present that would indicate it is more likely than not that the fair value of the reporting unit is less than its carrying amount. As part of the evaluation, we compare our estimate of the fair value of the reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. Judgments and assumptions are inherent in our management's estimates of fair value.

Other intangible assets

Our identifiable intangible assets 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 management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's 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 management's 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.

97

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

Judgments and assumptions are inherent in our management's 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 physical 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 Other noncurrent liabilities 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.

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

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 effective portion of the change in fair value of the derivative is reported in Accumulated other comprehensive income (loss) (AOCI) in the Consolidated Balance Sheet and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in Product sales or Product costs in the Consolidated Statement of Operations. 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 management.

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

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 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.

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

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 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.

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.

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, natural gas, and olefins that we purchase from our producer customers as part of the overall service provided to producers. Revenues from marketing NGLs 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 domestic olefins business produces olefins from purchased or produced feedstock and we recognize revenues when the olefins are sold and delivered.

Our Canadian business has processing and fractionation operations where we retain certain NGLs and olefins from an upgrader's offgas stream and we recognize revenues when the fractionated products are 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, net of estimated forfeitures, on a straight-line basis. (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 are actuarially determined and impacted by various assumptions and estimates. (See Note 9 – 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. 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 12 years for our pension plans and approximately 7 years for our other postretirement benefit plans. Unrecognized prior service costs and credits for the other postretirement benefit plans are amortized on a straight line basis over the average remaining years of service to eligibility for eligible plan participants, which is approximately 4 years.

The expected return on plan assets component of net periodic benefit cost 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.

In May 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-07 "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)" (ASU 2015-07). ASU 2015-07 removes from the fair value hierarchy investments measured using the net asset value per share (or its equivalent) practical expedient. The standard primarily impacts the presentation of certain investments included in our employee benefit plans. The standard is effective for financial statements issued for interim and annual reporting periods beginning after December 15, 2015, and requires retrospective presentation. Early adoption is permitted. Management elected to early adopt the provisions of this new standard. As a result, the plan asset investments measured at fair value using the net asset value per share (or its equivalent) practical expedient have been excluded from the presentation of plan assets within the fair value hierarchy. This standard has been applied retrospectively to the presentation of prior periods, as required upon adoption. (See Note 9 – Employee Benefit Plans.)

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 management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

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

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.
Foreign currency translation
Certain of our foreign subsidiaries use the Canadian dollar as their functional currency. Assets and liabilities of such foreign subsidiaries are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of AOCI in the Consolidated Balance Sheet.
Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates when the transactions are settled result in transaction gains and losses which are reflected in Other (income) expense – net in the Consolidated Statement of Operations.
Accounting standards issued but not yet adopted
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. The new standard clarifies the definition of a lease, requires a dual approach to lease classification similar to current lease classifications, and causes lessees to recognize leases on the balance sheet as a lease liability with a corresponding right-of-use asset for leases with a lease term of more than twelve months. The new standard is effective for interim and annual periods beginning after December 15, 2018. Early adoption is permitted. The new standard requires a modified retrospective transition for capital or operating leases existing at or entered into after the beginning of the earliest comparative period presented in the financial statements, but it does not require transition accounting for leases that expire prior to the date of initial application. We are evaluating the impact of the new standard on our consolidated financial statements.
In January 2016, the FASB issued ASU 2016-01 "Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01). ASU 2016-01 addresses certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. The new standard is effective for interim and annual periods beginning after December 15, 2017. Early adoption is only permitted for certain applications. We are evaluating the impact of the new standard on our consolidated financial statements and our timing for adoption.
In November 2015, the FASB issued ASU 2015-17 "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes" (ASU 2015-17). ASU 2015-17 requires that deferred income tax liabilities and assets be presented as noncurrent in a classified statement of financial position. The new standard is effective for interim and annual periods beginning after December 15, 2016, with either prospective or retrospective presentation allowed. Early adoption is permitted. Adoption of this standard will result in a change to the presentation of deferred taxes in our Consolidated Balance Sheet as the current deferred tax balance will be reclassified to a noncurrent deferred tax balance. The standard will have no impact on our Consolidated Statement of Operations and Consolidated Statement of Cash Flows.
In September 2015, the FASB issued ASU 2015-16 "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments" (ASU 2015-16). ASU 2015-16 requires an entity to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment

amounts are determined; record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date; and present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new standard is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted for financial statements that have not been issued. We do not expect the new standard will have a significant impact on our consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11 "Simplifying the Measurement of Inventory" (ASU 2015-11). ASU 2015-11 simplifies the guidance on the subsequent measurement of inventory, excluding inventory measured using last-in, first-out or the retail inventory method. Under the new standard, in scope inventory should be measured at the lower of cost and net realizable value. The new standard is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted. We measure inventory at the lower of cost or market; upon adoption, we will measure inventory at the lower of cost and net realizable value. We do not expect the new standard will have a material impact on the value of inventory reported in our consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02 "Amendments to the Consolidation Analysis" (ASU 2015-02). ASU 2015-02 alters the models used to determine consolidation conclusions for certain entities, including limited partnerships, and may require additional disclosures. The standard is effective for financial statements issued for interim and annual reporting periods beginning after December 15, 2015, with either retrospective or modified retrospective presentation allowed. Upon adoption of the new standard, WPZ will qualify as a VIE and will be disclosed accordingly. The new standard will have no significant impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09 establishing ASC Topic 606, "Revenue from Contracts with Customers" (ASC 606). ASC 606 establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to be entitled to receive in exchange for those goods or services and requires significantly enhanced revenue disclosures. In August 2015, the FASB issued ASU 2015-14 "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date" (ASU 2015-14). Per ASU 2015-14, the standard is effective for interim and annual reporting periods beginning after December 15, 2017. ASC 606 allows either full retrospective or modified retrospective transition and early adoption is permitted for annual periods beginning after December 15, 2016. We continue to evaluate both the impact of this new standard on our consolidated financial statements and the transition method we will utilize for adoption.

Note 2 – Acquisitions

ACMP

On December 20, 2012, we purchased approximately 24 percent of ACMP's outstanding limited partnership units and 50 percent of the ACMP general partner 2 percent interest which includes IDRs for approximately $2.19 billion in cash, including transaction costs. We accounted for these acquired interests as equity-method investments.

On July 1, 2014, we acquired control of ACMP (ACMP Acquisition) through the acquisition of an additional 26 percent of ACMP's outstanding limited partnership units and the remaining 50 percent interest in the general partner for $5.995 billion in cash. The acquisition was funded through the issuance of equity (see Note 15 – Stockholders' Equity) and debt (see Note 14 – Debt, Banking Arrangements, and Leases), credit facility borrowings, and cash on hand.

At the time of acquisition, ACMP owned, operated, developed, and acquired natural gas gathering systems and other midstream energy assets. The purpose of the acquisition was to enhance our position in the Marcellus and Utica shale plays, provide additional diversity via the Eagle Ford, Haynesville, Barnett, Mid-Continent, and Niobrara areas, and to fortify our stable, fee-based business model and support our dividend growth strategy.

Our basis in ACMP reflects business combination accounting, which, among other things, requires identifiable assets acquired and liabilities assumed to be measured at their acquisition-date fair values. Prior to the ACMP Acquisition we accounted for our investment in ACMP using the equity method. The acquisition-date fair value of our equity-method investment in ACMP was $4.6 billion. As a result of remeasuring our equity-method investment to fair value,

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

for the year ended December 31, 2014 we recognized a $2.5 billion noncash gain within the Gain on remeasurement of equity-method investment line item in the Consolidated Statement of Operations.
The valuation techniques used to measure the acquisition-date fair value of the ACMP Acquisition, including our previous equity-method investment in ACMP, consisted of valuing the limited partner units and general partner interest separately. The limited partner units, consisting of common and Class B units, were valued based on ACMP's closing common unit price at July 1, 2014. The general partner interest, including IDRs, was valued on a noncontrolling basis using an income approach based on a discounted cash flow analysis and a market comparison analysis based on comparable guideline companies and an implied fair value from our purchase.
The following table presents the allocation of the acquisition-date fair value of the major classes of the assets acquired, which are presented in the Williams Partners segment, liabilities assumed, and noncontrolling interest at July 1, 2014. The fair value of accounts receivable acquired equaled contractual amounts receivable. Changes to the preliminary allocation disclosed in Exhibit 99.1 of our Form 8-K dated May 6, 2015, which were recorded in the first quarter of 2015, reflect an increase of $150 million in Property, plant, and equipment and $25 million in Goodwill, and a decrease of $168 million in Other intangible assets and $7 million in Investments. These adjustments during the measurement period were not considered significant to require retrospective revisions of our financial statements.

	(Millions)	
Accounts receivable	$168	
Other current assets	63	
Investments	5,865	
Property, plant, and equipment	7,165	
Goodwill	499	
Other intangible assets	8,841	
Current liabilities	(408	)
Debt	(4,052	)
Other noncurrent liabilities	(9	)
Noncontrolling interest in ACMP's subsidiaries	(958	)
Noncontrolling interest in ACMP	(6,544	)

Other intangible assets recognized in the acquisition are related to contractual customer relationships from gas gathering agreements with our customers. The basis for determining the value of these intangible assets was estimated future net cash flows to be derived from acquired contractual customer relationships discounted using a risk-adjusted discount rate. These intangible assets are being amortized on a straight-line basis over 30 years during which contractual customer relationships are expected to contribute to our cash flows. As estimated at the time of acquisition, approximately 56 percent of the expected future revenues from these contractual customer relationships were impacted by our ability and intent to renew or renegotiate existing customer contracts. 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 current contract periods (as estimated at the time of acquisition), the weighted-average periods to the next renewal or extension of the existing customer contracts was approximately 17 years.
The noncash adjustment to record the fair value of the noncontrolling interest in ACMP was determined based on the common units and ACMP's closing common unit price at July 1, 2014.
The following unaudited pro forma Revenues and Net income attributable to The Williams Companies, Inc. for the years ended December 31, 2014 and 2013, are presented as if the ACMP Acquisition had been completed on January 1, 2013. These pro forma amounts are not necessarily indicative of what the actual results would have been if

the acquisition had in fact occurred on the date or for the periods indicated, nor do they purport to project Revenues or Net income attributable to The Williams Companies, Inc. for any future periods or as of any date. These amounts do not give effect to any potential cost savings, operating synergies, or revenue enhancements to result from the transactions or the potential costs to achieve these cost savings, operating synergies, and revenue enhancements.

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

	December 31, 2014	2013
	(Millions)	
Revenues	$8,181	$7,906
Net income attributable to The Williams Companies, Inc.	$622	$356

Significant adjustments to pro forma Net income attributable to The Williams Companies, Inc. include the removal of the previously described $2.5 billion gain on remeasurement of equity-method investment, and include additional depreciation and amortization expense associated with reflecting the acquired investments, property, plant, and equipment, and other intangible assets at fair value. The adjustments assume estimated useful lives of 30 years. Other significant adjustments to pro forma Net income attributable to The Williams Companies, Inc. include interest expense related to debt financing associated with the acquisition as well as Net income attributable to noncontrolling interests.

During the year ended December 31, 2014, ACMP contributed Revenues of $781 million and Net income attributable to The Williams Companies, Inc. of $165 million.

Costs related to this acquisition were $16 million in 2014 and are reported within our Williams Partners segment and included in Selling, general, and administrative expenses in our Consolidated Statement of Operations. Direct transaction costs associated with financing commitments were $9 million in 2014 and reported within Interest incurred in our Consolidated Statement of Operations. Equity earnings (losses) within our Consolidated Statement of Operations in 2014 includes $19 million of equity losses associated with certain compensation-related costs at ACMP that were triggered by the acquisition.

Eagle Ford Gathering System

In May 2015, WPZ acquired a gathering system comprised of approximately 140 miles of pipeline and a sour gas compression facility in the Eagle Ford shale for $112 million. The acquisition was accounted for as a business combination, and the allocation of the acquisition-date fair value of the major classes of assets acquired includes $80 million of Property, plant, and equipment, at cost and $32 million of Other intangible assets – net of accumulated amortization in the Consolidated Balance Sheet. Changes to the preliminary allocation disclosed in the second quarter of 2015 reflect an increase of $20 million in Property, plant, and equipment, at cost, and a decrease of $20 million in Other intangible assets – net of accumulated amortization.

UEOM Equity-Method Investment

In June 2015, WPZ acquired an approximate 13 percent additional interest in its equity-method investment, UEOM, for $357 million. Following the acquisition WPZ owns approximately 62 percent of UEOM. However, WPZ continues to account for this as an equity-method investment because WPZ does not control UEOM due to the significant participatory rights of its partner. In connection with the acquisition of the additional interest, we have agreed to waive approximately $2 million of our WPZ IDR payments each quarter through 2017.

Note 3 – Variable Interest Entities

As of December 31, 2015, we consolidate the following VIEs:

Gulfstar One

WPZ owns a 51 percent interest in Gulfstar One LLC (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 for the Tubular Bells oil and gas discovery in the eastern deepwater Gulf of Mexico. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Gulfstar One’s economic performance. Construction of an expansion project is underway that will provide production handling and gathering services for the Gunflint oil and gas discovery

105

in the eastern deepwater Gulf of Mexico. The expansion project is expected to be in service in the first half of 2016. The current estimate of the total remaining construction cost for the expansion project is approximately $130 million, which is expected to be funded with revenues received from customers and capital contributions from WPZ and the other equity partner on a proportional basis.

Constitution

WPZ owns 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. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Constitution's economic performance. WPZ, as construction manager for Constitution, is 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. WPZ plans to place the project in service in the fourth quarter of 2016, assuming timely receipt of all necessary regulatory approvals, and estimates the total remaining cost of the project to be approximately $571 million, which is expected to be funded with capital contributions from WPZ and the other equity partners on a proportional basis.

Cardinal

WPZ owns a 66 percent interest in Cardinal Gas Services, L.L.C (Cardinal), a subsidiary that provides gathering services for the Utica region and is a VIE due to certain risks shared with customers. WPZ is the primary beneficiary because it has 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 WPZ and the other equity partner on a proportional basis.

Jackalope

WPZ owns a 50 percent interest in Jackalope Gas Gathering Services, L.L.C (Jackalope), a subsidiary that provides gathering and processing services for the Powder River basin and is a VIE due to certain risks shared with customers. WPZ is the primary beneficiary because it has the power to direct the activities that most significantly impact Jackalope's economic performance. Future expansion activity is expected to be funded with capital contributions from WPZ 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,		
	2015	2014	Classification
	(Millions)		
Assets (liabilities):			
Cash and cash equivalents	$70	$113	Cash and cash equivalents
Accounts receivable	71	52	Accounts and notes receivable – net, Trade and other
Other current assets	2	3	Other current assets and deferred charges
Property, plant, and equipment – net	3,000	2,794	Property, plant, and equipment – net
Goodwill	47	103	Goodwill
Other intangible assets – net	1,436	1,493	Other intangible assets – net of accumulated amortization
Other noncurrent assets	—	14	Regulatory assets, deferred charges, and other
Accounts payable	(59)	(48)	Accounts payable
Accrued liabilities	(14)	(36)	Accrued liabilities
Current deferred revenue	(62)	(45)	Accrued liabilities
Noncurrent deferred income taxes	—	(13)	Deferred income tax liabilities
Asset retirement obligation	(93)	(94)	Other noncurrent liabilities
Noncurrent deferred revenue associated with customer advance payments	(331)	(395)	Other noncurrent liabilities

Note 4 – 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 $187 million, $197 million, and $161 million for the years ended 2015, 2014, and 2013, respectively. We have $12 million and $13 million included in Accounts payable in the Consolidated Balance Sheet with our equity-method investees at December 31, 2015 and 2014, respectively.

WPZ has operating agreements with certain equity-method investees. These operating agreements typically provide for reimbursement or payment to WPZ for certain direct operational payroll and employee benefit costs, materials, supplies, and other charges and also for management services. We supplied a portion of these services, primarily those related to employees since WPZ does not have any employees, to certain equity-method investees. The total gross charges to equity-method investees for these fees included in the Consolidated Statement of Operations are $64 million, $65 million, and $67 million for the years ended 2015, 2014, and 2013, respectively.

Board of Directors

A member of our Board of Directors, who was elected in 2013, is also the current chairman, president, and chief executive officer of an energy services company that is a customer of ours. We recorded $111 million, $115 million, and $131 million in Service revenues in the Consolidated Statement of Operations from this company for transportation and storage of natural gas for the years ended December 31, 2015, 2014, and 2013, respectively.

Note 5 – Investing Activities

Gain on remeasurement of equity-method investment in the Consolidated Statement of Operations

We recognized a $2.544 billion noncash gain in 2014 associated with the ACMP Acquisition. (See Note 2 – Acquisitions.)

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

Impairment of equity-method investments in the Consolidated Statement of Operations

During the third quarter of 2015, we recognized other-than-temporary impairment charges of $458 million and $3 million related to WPZ's equity-method investments in the Delaware basin gas gathering system and certain of the Appalachia Midstream Investments, respectively. During the fourth quarter of 2015, we recognized additional impairment charges for these investments of $45 million and $559 million, respectively, as well as impairment charges of $241 million and $45 million associated with WPZ's equity-method investments in UEOM and Laurel Mountain, respectively. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.) These charges are reported within the Williams Partners segment.

Equity earnings (losses) in the Consolidated Statement of Operations

Equity earnings (losses) in 2015 includes a loss of $19 million associated with WPZ's share of underlying property impairments at certain of the Appalachia Midstream Investments. This loss is reported within the Williams Partners segment.

Equity earnings (losses) in 2014 includes:

- Write-offs of capitalized project development costs on our discontinued investments in Bluegrass Pipeline of $67 million and Moss Lake of $4 million;
- a $7 million equity loss recognized from our interest in ACMP that was accounted for under the equity-method of accounting for the first six months of the year, including $19 million of equity losses associated with certain compensation-related costs at ACMP that were triggered by the acquisition and $30 million noncash amortization of the difference between the cost of our investment and our underlying share of the net assets for the first six months of the year.

Equity earnings (losses) in 2013 includes $93 million of equity earnings recognized from our interest in ACMP, acquired at the end of 2012, that was accounted for under the equity-method of accounting, partially offset by $63 million noncash amortization of the difference between the cost of our investment and our underlying share of the net assets.

Other investing income (loss) – net in the Consolidated Statement of Operations

Other investing income (loss) – net includes $27 million, $41 million, and $50 million of interest income for 2015, 2014 and 2013, respectively, 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.

Other investing income (loss) – net in 2013 also includes a $31 million gain resulting from ACMP's equity issuances during 2013. These equity issuances resulted in the dilution of our limited partner interest at that time from approximately 24 percent to 23 percent, which is accounted for as though we sold a portion of our investment.

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

Investments in the Consolidated Balance Sheet

	December 31,	
	2015	2014
	(Millions)	
Equity-method investments:		
Appalachia Midstream Investments (1)	$2,464	$3,033
UEOM — 62% (2)	1,525	1,411
Delaware basin gas gathering system — 50%	977	1,478
Discovery — 60%	602	602
OPPL – 50%	445	453
Caiman II — 58%	418	432
Laurel Mountain — 69%	391	459
Gulfstream — 50%	293	317
Other	221	215
	$7,336	$8,400

____

(1) Includes equity-method investments in multiple gathering systems in the Marcellus Shale with an approximate average 45 percent interest.
(2) WPZ acquired an approximate 13 percent additional interest in UEOM in 2015. (See Note 2 – Acquisitions).

We have differences between the carrying value of our equity-method investments and the underlying equity in the net assets of the investees of $2.4 billion at December 31, 2015 and $3.7 billion at December 31, 2014. These differences primarily relate to our investments in Appalachian Midstream Investments, Delaware basin gas gathering system, 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 in the Consolidated Statement of Cash Flows

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,		
	2015	2014	2013
	(Millions)		
UEOM (1)	$357	$57	$—
Appalachia Midstream Investments	93	84	—
Delaware basin gas gathering system	57	20	—
Discovery	35	106	193
Caiman II	—	175	192
Other	53	40	70
	$595	$482	$455

____

(1) 2015 includes additional interest in UEOM acquired by WPZ. (See Note 2 – Acquisitions.)

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 interest 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,		
	2015	2014	2013
	(Millions)		
Appalachia Midstream Investments	$219	$130	$—
Discovery	116	36	12
Gulfstream	88	81	81
OPPL	45	27	27
UEOM	42	—	—
Caiman II	33	13	—
Delaware basin gas gathering system	33	—	—
Laurel Mountain	31	39	—
Access Midstream Investments	—	64	93
Other	26	50	34
	$633	$440	$247

In addition, on September 24, 2015, WPZ received a special distribution of $396 million from Gulfstream reflecting its proportional share of the proceeds from new debt issued by Gulfstream. The new debt was issued to refinance Gulfstream's debt maturities. Subsequently, WPZ contributed $248 million to Gulfstream for its proportional share of amounts necessary to fund debt maturities of $500 million due on November 1, 2015. WPZ also expects to contribute its proportional share of amounts necessary to fund debt maturities of $300 million due on June 1, 2016, as reflected by the accrued liability of $149 million in Accrued liabilities in the Consolidated Balance Sheet at December 31, 2015.

Summarized Financial Position and Results of Operations of All Equity-Method Investments

	December 31,	
	2015	2014
	(Millions)	
Assets (liabilities):		
Current assets	$773	$599
Noncurrent assets	9,549	9,135
Current liabilities	(633)	(850)
Noncurrent liabilities	(1,450)	(954)

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Gross revenue	$1,707	$1,623	$2,406
Operating income	690	534	699
Net income	611	460	627

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

Note 6 – Other Income and Expenses

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Williams Partners			
Impairment of certain assets (See Note 17)	$145	$52	$—
Amortization of regulatory assets associated with asset retirement obligations	33	33	30
Contingency gain settlement (1)	—	(154)	—
Net gain related to partial acreage dedication release	—	(12)	—
Loss related to sale of certain assets	—	10	—
Write-off of the Eminence abandonment regulatory asset not recoverable through rates	—	(3)	12
Insurance recoveries associated with the Eminence abandonment	—	—	(16)
Loss associated with a producer claim	—	—	25
Williams NGL & Petchem Services			
Impairment of certain assets (See Note 17)	64	—	20

(1) In November 2014, we settled a claim arising from the resolution of a contingent gain related to claims associated with the purchase of a business in a prior period. Pursuant to the settlement, we received $154 million in cash, all of which was recognized as a gain in the fourth quarter of 2014.

Geismar Incident

On June 13, 2013, an explosion and fire occurred at Williams Partners' Geismar olefins plant. The incident rendered the facility temporarily inoperable (Geismar Incident).

In 2015, 2014, and 2013, we received $126 million, $246 million, and $50 million, respectively, of insurance recoveries related to the Geismar Incident. These amounts are reported within the Williams Partners segment and reflected as gains in Net insurance recoveries – Geismar Incident in our Consolidated Statement of Operations. Also, in 2014 and 2013, we incurred $14 million and $10 million, respectively, of covered insurable expenses in excess of our retentions (deductibles) also included in Net insurance recoveries – Geismar Incident in the Consolidated Statement of Operations and we expensed $13 million within the Williams Partners segment in 2013 of costs under our insurance deductibles reported in Operating and maintenance expenses in the Consolidated Statement of Operations.

ACMP Acquisition & Merger

Certain ACMP Acquisition and ACMP Merger costs included in Selling, general, and administrative expenses, Operating and maintenance expenses, and Interest incurred in the Consolidated Statement of Operations are as follows:

- Selling, general, and administrative expenses includes $26 million in 2015 and $27 million in 2014 (including $16 million of ACMP Acquisition costs) primarily related to professional advisory fees associated with the ACMP Acquisition and ACMP Merger within the Williams Partners segment.
- Selling, general, and administrative expenses includes $9 million in 2015 and $15 million in 2014 of related employee transition costs from the ACMP Merger within the Williams Partners segment and $32 million in 2015 and $10 million in 2014 of general corporate expenses associated with integration and realignment of resources within the Other segment.

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

- Operating and maintenance expenses includes $12 million in 2015 and $15 million in 2014 of transition costs from the ACMP Merger within the Williams Partners segment.
- Interest incurred includes transaction-related financing costs of $2 million in 2015 from the ACMP Merger and $9 million in 2014 from the ACMP Acquisition.

Additional Items

Certain items included in Service revenues, Product costs, Selling, general, and administrative expenses and Other income (expense) – net below Operating income (loss) in the Consolidated Statement of Operations are as follows:

- Service revenues includes $239 million recognized in the fourth quarter of 2015 and $167 million recognized in the fourth quarter of 2014 from minimum volume commitment fees within the Williams Partners segment.
- Product costs includes $6 million in 2015 and $27 million in 2014 of inventory adjustments within the Williams Partners segment.
- Selling, general, and administrative expenses includes $30 million in 2015 of costs associated with our evaluation of strategic alternatives within the Other segment.
- Selling, general, and administrative expenses includes $18 million in 2014 of project development costs related to the Bluegrass Pipeline reported within the Williams NGL & Petchem Services segment.
- Other income (expense) – net below Operating income (loss) includes $95 million, $44 million, and $22 million for equity AFUDC for 2015, 2014, and 2013, respectively. Equity AFUDC increased during 2015 due to the increase in spending on various Transco expansion projects and Constitution.
- Other income (expense) – net below Operating income (loss) includes a $14 million gain in 2015 resulting from the early retirement of certain debt within the Williams Partners segment.

Note 7 – Provision (Benefit) for Income Taxes

The Provision (benefit) for income taxes includes:

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Current:			
Federal	$—	$(9)	$(17)
State	(7)	2	7
Foreign	(55)	10	(13)
	(62)	3	(23)
Deferred:			
Federal	(317)	1,108	348
State	(25)	119	40
Foreign	5	19	36
	(337)	1,246	424
Provision (benefit) for income taxes	$(399)	$1,249	$401

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

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Provision (benefit) at statutory rate	$(600)	$1,255	$378
Increases (decreases) in taxes resulting from:			
Impact of nontaxable noncontrolling interests	263	(75)	(78)
State income taxes (net of federal benefit)	(21)	82	26
Foreign operations – net	8	(11)	(32)
Taxes on undistributed earnings of foreign subsidiaries – net	—	(37)	99
Translation adjustment of certain unrecognized tax benefits	(71)	—	—
Other – net	22	35	8
Provision (benefit) for income taxes	$(399)	$1,249	$401

Income (loss) from continuing operations before income taxes includes $20 million, $102 million, and $119 million of foreign income in 2015, 2014, and 2013, respectively.

The 2015 federal and state income tax provisions include the tax effect of a $2.7 billion impairment loss associated with certain goodwill, equity-method investments, and other assets. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk). The Translation adjustment of certain unrecognized tax benefits in 2015 reflects the impact of changes in foreign currency exchange rates on the remeasurement of a foreign currency denominated unrecognized tax benefit, including associated penalties and interest.

The 2014 federal and state income tax provisions include the tax effect of a $2.5 billion gain associated with remeasuring our equity-method investment to fair value as a result of the ACMP Acquisition. (See Note 2 – Acquisitions).

On October 30, 2013, WPZ announced its intent to pursue an agreement to acquire certain of our Canadian operations. As a result, we no longer considered the undistributed earnings from these foreign operations to be permanently reinvested and thus recognized $99 million of deferred income tax expense in continuing operations and $24 million of deferred income tax benefit in AOCI during 2013. Taxes on undistributed earnings of foreign subsidiaries – net decreased in 2014 due to revisions of our estimate of the undistributed earnings, partially offset by an increase of tax expense, which decreased our share of the foreign tax credit due to the Canada Dropdown.

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 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.

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

Significant components of Deferred income tax liabilities and Deferred income tax assets are as follows:

	December 31,	
	2015	2014
	(Millions)	
Deferred income tax liabilities:		
Property, plant, and equipment	$4	$4
Investments	5,272	5,472
Other	15	10
Total deferred income tax liabilities	5,291	5,486
Deferred income tax assets:		
Accrued liabilities	150	178
Minimum tax credits	139	137
Foreign tax credit	193	251
Federal loss carryovers	485	134
State losses and credits	296	250
Other	42	97
Total deferred income tax assets	1,305	1,047
Less valuation allowance	190	206
Net deferred income tax assets	1,115	841
Overall net deferred income tax liabilities	$4,176	$4,645

The valuation allowance at December 31, 2015 and 2014 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, and have determined that a portion of our deferred income tax assets related to State losses and credits may not be realized. The change in Valuation allowance is due to this evaluation. 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 is primarily due to 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. These attributes generally expire between 2016 and 2035 with some carryovers having indefinite carryforward periods. The federal tax Minimum tax credits of $139 million currently has no expiration date. Foreign tax credit of $139 million is expected to be utilized prior to expiration in 2025. The remaining Foreign tax credit represents unrealized foreign tax credit that will be allocated to us in the future when deferred income tax liabilities associated with temporary differences on foreign assets and liabilities become current income tax liabilities in the foreign jurisdiction.

Federal net operating loss carryovers and charitable contribution carryovers of $1.5 billion at the end of 2015 are expected to be utilized by us prior to expiration between 2018 and 2035. Employee share-based compensation attributable to the exercise of stock options and vesting of restricted stock is deductible by us for tax purposes. To the extent these tax deductions exceed the previously accrued deferred income tax benefit for these items, the additional tax benefit is not recognized until the deduction reduces current income taxes payable. Since the additional tax benefit does not reduce our current income taxes payable for 2015 and 2014, these tax benefits are not included in our Federal loss carryovers deferred income tax assets. The additional tax benefits deductible for tax purposes but not included in our Federal loss carryovers deferred income tax assets were $23 million each for 2015 and 2014.

Cash refunds for income taxes (net of payments and discontinued operations) were $136 million and $50 million in 2015 and 2013, respectively. Cash payments for income taxes (net of refunds) in 2014 were $29 million.

As of December 31, 2015, we had approximately $55 million of unrecognized tax benefits. If recognized, income tax expense would be reduced by $51 million, 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:

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

	2015	2014
	(Millions)	
Balance at beginning of period	$89	$66
Additions based on tax positions related to the current year	—	11
Additions for tax positions of prior years	2	12
Reductions for tax positions of prior years	—	—
Settlement with taxing authorities	—	—
Changes due to currency translation	(36)	—
Balance at end of period	$55	$89

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 benefits of $22 million for 2015, including a $35 million benefit due to currency fluctuation, and expense of $8 million and $9 million for 2014 and 2013, respectively. Approximately $2 million and $24 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2015 and 2014, respectively. Changes due to currency translation in 2015 reflects the unrecognized tax benefit portion of the previously described impact of changes in foreign currency exchange rates on the remeasurement of a foreign currency denominated balance.

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 IRS examination for years after 2010. As of December 31, 2015, 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 Canadian entities are open to audit for tax years after 2010.

On September 13, 2013, the IRS issued final regulations providing guidance on the treatment of amounts paid to acquire, produce, or improve tangible property. On August 18, 2014, the IRS issued final regulations providing guidance on the dispositions of such property. The implementation date for these regulations was January 1, 2014. The IRS is expected to issue additional procedural guidance regarding how the requirements may be implemented for the gas transmission and distribution industry. Pending the issuance of this additional procedural guidance from the IRS, we cannot at this time estimate the impact of implementing the regulations for our gas transmission business, although we anticipate that it will result in an immaterial balance sheet only impact.

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

Note 8 – Earnings (Loss) Per Common Share from Continuing Operations

	Years Ended December 31,		
	2015	2014	2013
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$(571)	$2,110	$441
Basic weighted-average shares	749,271	719,325	682,948
Effect of dilutive securities:			
Nonvested restricted stock units	—	2,234	1,995
Stock options	—	2,064	2,149
Convertible debentures	—	18	93
Diluted weighted-average shares (1)	749,271	723,641	687,185
Earnings (loss) per common share from continuing operations:			
Basic	$(.76)	$2.93	$0.65
Diluted	$(.76)	$2.91	$0.64

(1) For the year ended December 31, 2015, 1.7 million weighted-average nonvested restricted stock units and 1.5 million weighted-average stock options have been excluded from the computation of diluted earnings (loss) per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to The Williams Companies, Inc.

Note 9 – 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. Various other formulas, as defined in the plan documents, are utilized to calculate the retirement benefits for plan participants not covered by the 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 a lump sum and annuity 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, and other miscellaneous defined participant groups. 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 these plans 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.

The Williams Companies, Inc.
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	
	2015	2014	2015	2014
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,544	$1,384	$233	$213
Service cost	59	40	2	2
Interest cost	58	62	9	10
Plan participants' contributions	—	—	2	2
Benefits paid	(101)	(86)	(13)	(14)
Plan amendment	—	—	—	1
Actuarial loss (gain)	(91)	144	(31)	21
Settlements	(5)	(3)	—	(1)
Curtailments	—	—	—	(1)
Other	—	3	—	—
Benefit obligation at end of year	1,464	1,544	202	233
Change in plan assets:				
Fair value of plan assets at beginning of year	1,293	1,241	208	201
Actual return on plan assets	(11)	78	(1)	13
Employer contributions	65	63	5	6
Plan participants' contributions	—	—	2	2
Benefits paid	(101)	(86)	(13)	(14)
Settlements	(5)	(3)	—	—
Fair value of plan assets at end of year	1,241	1,293	201	208
Funded status — underfunded	$(223)	$(251)	$(1)	$(25)
Accumulated benefit obligation	$1,432	$1,516		

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

	December 31,	
	2015	2014
	(Millions)	
Underfunded pension plans:		
Current liabilities	$(2)	$(2)
Noncurrent liabilities	(221)	(249)
Underfunded other postretirement benefit plans:		
Current liabilities	(7)	(7)
Noncurrent assets (liabilities)	6	(18)

The plan assets within our other postretirement benefit plans are intended to be used for the payment of benefits for certain groups of participants. The Current liabilities for the other postretirement benefit plans 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 Actuarial loss (gain) of $(91) million in 2015 is primarily due to the impact of a decrease in the assumed future interest crediting rate for the cash balance pension formula and an increase in the discount rates utilized to calculate the benefit obligation. The pension plans’ benefit obligation Actuarial loss (gain) of $144 million in 2014 is primarily due to the impact of updated mortality tables reflecting increased estimated life expectancies and a decrease in the discount rates utilized to calculate the benefit obligation.

The 2015 benefit obligation Actuarial loss (gain) of $(31) million for our other postretirement benefit plans is primarily due to an increase in the discount rate used to calculate the benefit obligation, tax law changes, and other assumption changes. The 2014 benefit obligation Actuarial loss (gain) of $21 million for our other postretirement benefit plans is primarily due to the impact of the updated mortality tables and a decrease in the discount rates utilized to calculate the benefit obligation.

At December 31, 2015 and 2014, 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 at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(Millions)			
Amounts included in Accumulated other comprehensive income (loss):				
Prior service credit	$—	$—	$11	$17
Net actuarial loss	(544)	(593)	(18)	(28)
Amounts included in regulatory liabilities associated with Transco and Northwest Pipeline:				
Prior service credit	N/A	N/A	$19	$30
Net actuarial gain (loss)	N/A	N/A	6	(4)

In addition to the regulatory liabilities included in the previous table, differences in the amount of actuarially determined Net periodic benefit cost for our other postretirement benefit plans 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 $78 million at December 31, 2015 and $62 million at December 31, 2014, related to these deferrals. These amounts will be reflected in future rates based on the rate structures of these gas pipelines.

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

Net Periodic Benefit Cost

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

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
	(Millions)					
Components of net periodic benefit cost:						
Service cost	$59	$40	$44	$2	$2	$2
Interest cost	58	62	51	9	10	11
Expected return on plan assets	(75)	(76)	(61)	(12)	(12)	(9)
Amortization of prior service cost (credit)	—	—	1	(17)	(20)	(12)
Amortization of net actuarial loss	42	39	60	2	—	4
Net actuarial (gain) loss from settlements and curtailments	2	1	—	—	(1)	—
Reclassification to regulatory liability	—	—	—	3	4	2
Net periodic benefit cost	$86	$66	$95	$(13)	$(17)	$(2)

Items Recognized in Other Comprehensive Income (Loss) and Regulatory Assets/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		
	2015	2014	2013	2015	2014	2013
	(Millions)					
Other changes in plan assets and benefit obligations recognized in Other comprehensive income (loss):						
Net actuarial gain (loss)	$5	$(142)	$277	$8	$(18)	$23
Prior service (cost) credit	—	—	—	—	(1)	23
Amortization of prior service cost (credit)	—	—	1	(6)	(8)	(4)
Amortization of net actuarial loss	42	39	60	2	—	1
Loss from settlements and curtailments	2	1	—	—	1	—
Other changes in plan assets and benefit obligations recognized in Other comprehensive income (loss)	$49	$(102)	$338	$4	$(26)	$43

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

	2015	2014	2013
	(Millions)		
Other changes in plan assets and benefit obligations recognized in regulatory (assets) liabilities:			
Net actuarial gain (loss)	$10	$(2)	$62
Prior service credit	—	—	36
Amortization of prior service credit	(11)	(12)	(8)

Amortization of net actuarial loss	—	—	3

119

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

Pre-tax amounts expected to be amortized in Net periodic benefit cost in 2016 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in Accumulated other comprehensive income (loss):		
Prior service credit	$—	$(6)
Net actuarial loss	31	—
Amounts included in regulatory liabilities associated with Transco and Northwest Pipeline:		
Prior service credit	N/A	$(9)
Net actuarial loss	N/A	—

Key Assumptions

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

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Discount rate	4.38 %	3.96 %	4.50 %	4.12 %
Rate of compensation increase	4.88	4.62	N/A	N/A

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

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	3.96 %	4.68 %	3.43 %	4.12 %	4.80 %	3.97 %
Expected long-term rate of return on plan assets	6.38	6.85	5.90	5.70	6.11	5.26
Rate of compensation increase	4.62	4.56	4.57	N/A	N/A	N/A

Effective December 31, 2014, the mortality assumptions used to determine the benefit obligations for our pension and other postretirement benefit plans were updated to reflect generational projection mortality tables. These mortality tables generally reflect increased estimated life expectancy.

The assumed health care cost trend rate for 2016 is 7.9 percent. This rate decreases to 4.5 percent by 2025. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Point increase	Point decrease
	(Millions)	
Effect on total of service and interest cost components	$—	$—
Effect on other postretirement benefit obligation	7	(6)

Plan Assets

Plan assets for our pension and other postretirement benefit plans consist primarily of equity and fixed income securities including 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

120

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, 2015 of 60 percent equity securities and 40 percent fixed income securities. The target allocation includes the investments in equity and fixed income 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 in the pension plans 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 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 commingled investment funds. Additionally, real estate equity, natural resource property, venture capital, leveraged buyouts, and other high-return, high-risk investments are generally restricted.

As of December 31, 2015, 12 active investment managers and one passive investment manager managed substantially all of the pension plans' funds and the other postretirement benefit plans' funds were substantially managed by four active investment managers and one passive investment manager. Each of the managers had responsibility for managing a specific portion of these assets and each investment manager was responsible for 1 percent to 28 percent of the assets.

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

The fair values of our pension plan assets at December 31, 2015 and 2014 by asset class are as follows:

	2015			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Pension assets:				
Cash management fund	$8	$—	$—	$8
Equity securities:				
U.S. large cap	83	—	—	83
U.S. small cap	64	—	—	64
Fixed income securities (1):				
U.S. Treasury securities	65	—	—	65
Government and municipal bonds	—	8	—	8
Mortgage and asset-backed securities	—	87	—	87
Corporate bonds	—	145	—	145
Insurance company investment contracts and other	—	5	—	5
	$220	$245	$—	465
Commingled investment funds measured at net asset value practical expedient (3):				
Equities — U.S. large cap				367
Equities — International small cap				27
Equities — International emerging markets				50
Equities — International developed markets				153
Fixed income — U.S. long duration				95
Fixed income — Corporate bonds				84
Total assets at fair value at December 31, 2015				$1,241

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

	2014 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	$25	$—	$—	$25
Equity securities:				
U.S. large cap	221	—	—	221
U.S. small cap	139	—	—	139
International developed markets large cap growth	—	60	—	60
Fixed income securities (1):				
U.S. Treasury securities	31	—	—	31
Mortgage-backed securities	—	65	—	65
Corporate bonds	—	222	—	222
Insurance company investment contracts and other	—	7	—	7
	$416	$354	$—	770
Commingled investment funds measured at net asset value practical expedient (3):				
Equities — U.S. large cap				189
Equities — International small cap				24
Equities — Emerging markets value				27
Equities — Emerging markets growth				19
Equities — International developed markets large cap value				101
Fixed income — Corporate bonds				163
Total assets at fair value at December 31, 2014				$1,293

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

The fair values of our other postretirement benefits plan assets at December 31, 2015 and 2014 by asset class are as follows:

	2015 Quoted Prices in Active Markets for Identical Assets (Level 1) (Millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Other postretirement benefit assets:				
Cash management funds	$11	$—	$—	$11
Equity securities:				
U.S. large cap	37	—	—	37
U.S. small cap	20	—	—	20
International developed markets large cap growth	1	9	—	10
Emerging markets growth	—	1	—	1
Fixed income securities (2):				
U.S. Treasury securities	7	—	—	7
Government and municipal bonds	—	12	—	12
Mortgage and asset-backed securities	—	9	—	9
Corporate bonds	—	15	—	15
	$76	$46	$—	122
Commingled investment funds measured at net asset value practical expedient (3):				
Equities — U.S. large cap				37
Equities — International small cap				3
Equities — International emerging markets				5
Equities — International developed markets				16
Fixed income — U.S. long duration				10
Fixed income — Corporate bonds				8
Total assets at fair value at December 31, 2015				$201

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

	2014 Quoted Prices in Active Markets for Identical Assets (Level 1) (Millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Other postretirement benefit assets:				
Cash management funds	$13	$—	$—	$13
Equity securities:				
U.S. large cap	53	—	—	53
U.S. small cap	28	—	—	28
International developed markets large cap growth	—	15	—	15
Emerging markets growth	1	2	—	3
Fixed income securities (2):				
U.S. Treasury securities	3	—	—	3
Government and municipal bonds	—	11	—	11
Mortgage-backed securities	—	7	—	7
Corporate bonds	—	23	—	23
	$98	$58	$—	156
Commingled investment funds measured at net asset value practical expedient (3):				
Equities — U.S. large cap				19
Equities — International small cap				2
Equities — Emerging markets value				3
Equities — Emerging markets growth				2
Equities — International developed markets large cap value				10
Fixed income — Corporate bonds				16
Total assets at fair value at December 31, 2014				$208

(1) The weighted-average credit quality rating of the pension assets fixed income security portfolio is investment grade with a weighted-average duration of approximately 8 years for 2015 and 6 years for 2014.

(2) The weighted-average credit quality rating of the other postretirement benefit assets fixed income security portfolio is investment grade with a weighted-average duration of approximately 7 years for 2015 and 5 years for 2014.

(3) In accordance with our adoption of ASU 2015-07, investments measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified within the fair value hierarchy. (See Note 1 – General, Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies.)

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

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 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 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 value of the fund's 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.
The investment contracts with insurance companies are valued at fair value by discounting the cash flow of a bond using a yield to maturity based on an investment grade index or comparable index with a similar maturity value, maturity period, and nominal coupon rate.
There have been no significant changes in the preceding valuation methodologies used at December 31, 2015 and 2014. Additionally, there were no transfers or reclassifications of investments between Level 1 and Level 2 from December 2014 to December 2015. 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)	
2016	$95	$13
2017	102	13
2018	105	13
2019	106	13
2020	110	14
2021-2025	578	66

In 2016, we expect to contribute approximately $60 million to our tax-qualified pension plans and approximately $2 million to our nonqualified pension plans, for a total of approximately $62 million, and approximately $7 million to our other postretirement benefit plans.

126

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

Defined Contribution Plans
We also maintain defined contribution plans 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 plans' guidelines. We match employees' contributions up to certain limits. Our matching contributions charged to expense were $39 million in 2015, $39 million in 2014, and $27 million in 2013. The increase in expense beginning in 2014 is primarily due to the impact of the consolidation of ACMP beginning in the third quarter of 2014. (See Note 2 – Acquisitions.)
Note 10 – Inventories

	December 31,	
	2015	2014
	(Millions)	
Natural gas liquids, olefins, and natural gas in underground storage	$57	$150
Materials, supplies, and other	70	81
	$127	$231

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, 2015	2014
			(Millions)	
Nonregulated:				
Natural gas gathering and processing facilities	5 - 40		$20,789	$18,749
Construction in progress	Not applicable		1,366	2,648
Other	2 - 45		2,170	1,850
Regulated:				
Natural gas transmission facilities		1.20 - 6.97	12,189	10,867
Construction in progress	Not applicable	Not applicable	941	985
Other	5 - 45	1.35 - 33.33	1,584	1,336
Total property, plant, and equipment, at cost			39,039	36,435
Accumulated depreciation and amortization			(9,460)	(8,354)
Property, plant, and equipment — net			$29,579	$28,081

(1) Estimated useful life and depreciation rates are presented as of December 31, 2015. 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 $1,382 million, $967 million, and $752 million in 2015, 2014, and 2013, respectively.
Regulated Property, plant, and equipment – net includes approximately $706 million and $746 million at December 31, 2015 and 2014, 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.

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

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 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 following table presents the significant changes to our ARO, of which $858 million and $791 million are included in Other noncurrent liabilities with the remaining current portion in Accrued liabilities at December 31, 2015 and 2014, respectively.

	December 31,	
	2015	2014
	(Millions)	
Beginning balance	$831	$561
Liabilities incurred	42	101
Liabilities settled (1)	(3)	(21)
Accretion expense	60	44
Revisions (2)	(15)	146
Ending balance	$915	$831

(1) For 2014, liabilities settled include $7 million related to the abandonment of certain of Transco's natural gas storage caverns that are associated with a leak in 2010.

(2) Several factors are considered in the annual review process, including inflation rates, current estimates for removal cost, discount rates, and the estimated remaining useful life of the assets. The 2015 revisions reflect changes in removal cost estimates and the estimated remaining useful life of assets, a decrease in the inflation rate, and increases in the discount rates used in the annual review process. The 2014 revisions primarily reflect an increase in the estimated retirement costs for our offshore pipelines, an increase in the inflation rate, and decreases in the 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 – Goodwill and Other Intangible Assets

Goodwill

Changes in the carrying amount of goodwill by reportable segment for the periods indicated are as follows:

	Williams Partners
	(Millions)
December 31, 2014	$1,120
Purchase accounting adjustment	25
Impairment	(1,098)
December 31, 2015	$47

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

Our goodwill is not subject to amortization, but is evaluated at least annually for impairment or more frequently if impairment indicators are present. We did not identify or recognize any impairments to goodwill in connection with our annual evaluation of goodwill for impairment (performed as of October 1) during the years ended December 31, 2014 and 2013. During 2015, we performed an interim assessment of certain goodwill within the Williams Partners segment as of September 30, 2015, but the estimated fair value of the reporting unit evaluated exceeded its carrying amount and thus no impairment charge was recognized. We performed an additional goodwill impairment evaluation as of December 31, 2015, of the goodwill recorded within the Williams Partners segment. As a result of this evaluation, we recorded goodwill impairment charges totaling $1.098 billion. (See Note 17 – Fair Value Measurements, Guarantees, and Concentration of Credit Risk.)

Other Intangible Assets

The gross carrying amount and accumulated amortization of Other intangible assets – net of accumulated amortization at December 31 are as follows:

	2015 Gross Carrying Amount	Accumulated Amortization	2014 Gross Carrying Amount	Accumulated Amortization
	(Millions)			
Contractual customer relationships	$10,633	$(663)	$10,763	$(310)

Other intangible assets – net of accumulated amortization primarily relate to gas gathering, processing, and fractionation contractual customer relationships recognized in the ACMP and Eagle Ford acquisitions (See Note 2 – Acquisitions) as well as the 2012 acquisitions from Delphi Midstream Partners, LLC (Laser) and Caiman Energy, LLC (Caiman). The decrease in the gross carrying amount of Other intangible assets – net of accumulated amortization during 2015 is primarily related to the $168 million decrease from the purchase price allocation adjustment recorded for the ACMP acquisition in the first quarter of 2015, partially offset by the $32 million increase due to the Eagle Ford acquisition in the second quarter of 2015 (see Note 2 – Acquisitions). The 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 (as estimated at the time of the respective acquisition), the weighted-average periods prior to the next renewal or extension of the contractual customer relationships associated with the ACMP, Eagle Ford, Laser, and Caiman acquisitions were approximately 17 years, 10 years, 9 years, and 18 years, respectively. 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 – net of accumulated amortization was $353 million, $209 million, and $60 million in 2015, 2014, and 2013, respectively. The estimated amortization expense for each of the next five succeeding fiscal years is approximately $354 million.

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

Note 13 – Accrued Liabilities

	December 31, 2015	2014
	(Millions)	
Interest on debt	$284	$268
Employee costs	215	167
Special distribution repayable to Gulfstream (See Note 5 - Investing Activities)	149	—
Deferred income	94	82
Asset retirement obligations	57	40
Other, including other loss contingencies	279	343
	$1,078	$900

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

	December 31, 2015	2014
	(Millions)	
Unsecured:		
Transco:		
6.4% Notes due 2016 (2)	$200	$200
6.05% Notes due 2018	250	250
7.08% Debentures due 2026	8	8
7.25% Debentures due 2026	200	200
5.4% Notes due 2041	375	375
4.45% Notes due 2042	400	400
Northwest Pipeline:		
7% Notes due 2016	175	175
5.95% Notes due 2017	185	185
6.05% Notes due 2018	250	250
7.125% Debentures due 2025	85	85
WPZ:		
3.8% Notes due 2015 (1)	—	750
7.25% Notes due 2017	600	600
5.25% Notes due 2020	1,500	1,500
4.125% Notes due 2020	600	600
4% Notes due 2021	500	500
5.875% Notes due 2021	—	750
3.6% Notes due 2022	1,250	—
3.35% Notes due 2022	750	750
6.125% Notes due 2022	750	750
4.5% Notes due 2023	600	600
4.875% Notes due 2023	1,400	1,400

4.3% Notes due 2024	1,000	1,000
4.875% Notes due 2024	750	750
3.9% Notes due 2025	750	750
4.0% Notes due 2025	750	—

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

	December 31, 2015 (Millions)	2014
6.3% Notes due 2040	$1,250	$1,250
5.8% Notes due 2043	400	400
5.4% Notes due 2044	500	500
4.9% Notes due 2045	500	500
5.1% Notes due 2045	1,000	—
Term Loan, variable interest rate, due 2018	850	—
Credit facility loans	1,310	640
WMB:		
7.875% Notes due 2021	371	371
3.7% Notes due 2023	850	850
4.55% Notes due 2024	1,250	1,250
7.5% Debentures due 2031	339	339
7.75% Notes due 2031	252	252
8.75% Notes due 2032	445	445
5.75% Notes due 2044	650	650
Various — 5.5% to 10.25% Notes and Debentures due 2019 to 2033	55	55
Credit facility loans	650	370
Capital lease obligations	1	5
Debt issuance costs	(123)	(108)
Net unamortized debt premium (discount)	110	187
Total long-term debt, including current portion	23,988	20,784
Long-term debt due within one year	(176)	(4)
Long-term debt	$23,812	$20,780

____
(1) Presented as long-term debt at December 31, 2014, due to WPZ's intent and ability to refinance.
(2) Presented as long-term debt at December 31, 2015, due to Transco’s intent and ability to refinance.

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

	December 31, 2015 (Millions)
2016	$175
2017	785
2018	1,350
2019	32
2020	2,121

Provisions concerning ACMP long-term debt

Certain long-term debt originally issued by ACMP totaling $2.9 billion has provisions that would require WPZ to make an offer to repurchase such notes at 101 percent of the principle amount should WPZ's credit be downgraded by either Moody's Investor Service or Standard and Poor's within a period of ninety days following the completion of the proposed ETC Merger.

Issuances and retirements

On January 22, 2016, Transco issued $1 billion of 7.85 percent senior unsecured notes due 2026 to investors in a private debt placement. Transco intends to use the net proceeds from the offering to repay debt and to fund capital expenditures.

In December 2015, WPZ borrowed $850 million on a variable interest rate loan with certain lenders due 2018. At December 31, 2015 the interest rate was 1.85 percent. WPZ used the proceeds for working capital, capital expenditures, and for general partnership purposes.

On April 15, 2015, WPZ paid $783 million, including a redemption premium, to early retire $750 million of 5.875 percent senior notes due 2021 with a carrying value of $797 million.

On March 3, 2015, WPZ completed a public offering of $1.25 billion of 3.6 percent senior unsecured notes due 2022, $750 million of 4 percent senior unsecured notes due 2025, and $1 billion of 5.1 percent senior unsecured notes due 2045. WPZ used the net proceeds to repay amounts outstanding under its commercial paper program and credit facility, to fund capital expenditures, and for general partnership purposes.

WPZ retired $750 million of 3.8 percent senior unsecured notes that matured on February 15, 2015.

On June 27, 2014, Pre-merger WPZ completed a public offering of $750 million of 3.9 percent senior unsecured notes due 2025 and $500 million of 4.9 percent senior unsecured notes due 2045. Pre-merger WPZ used the net proceeds to repay amounts outstanding under its commercial paper program, to fund capital expenditures, and for general partnership purposes.

On June 24, 2014, we completed a public offering of $1.25 billion of 4.55 percent senior unsecured notes due 2024 and $650 million of 5.75 percent unsecured notes due 2044. We used the net proceeds to finance a portion of the ACMP Acquisition. (See Note 2 – Acquisitions.)

On March 4, 2014, Pre-merger WPZ completed a public offering of $1 billion of 4.3 percent senior unsecured notes due 2024 and $500 million of 5.4 percent senior unsecured notes due 2044. Pre-merger WPZ used the net proceeds to repay amounts outstanding under its commercial paper program, to fund capital expenditures, and for general partnership purposes.

Credit Facilities

	December 31, 2015	
	Available	Outstanding
	(Millions)	
WMB		
Long-term credit facility	$1,500	$650
Letters of credit under certain bilateral bank agreements		14
WPZ		
Long-term credit facility (1)	3,500	1,310
Letters of credit under certain bilateral bank agreements		2
Short-term credit facility	150	—

(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.

WMB long-term credit facility

On February 2, 2015, we entered into the Second Amended and Restated Credit Agreement. The aggregate commitments available remained at $1.5 billion, with up to an additional $500 million increase in aggregate commitments available under certain circumstances. The maturity date of the credit facility was extended to February 2, 2020. However, we 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 February 2, 2022, under certain circumstances. The agreement also allows for swing line loans up to an aggregate amount of $50 million, subject to available capacity under the credit facility, and the letters of credit up to $675 million.

The agreements governing the credit facilities contain 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, enter into certain affiliate transactions, make certain distributions during an event of default, make investments, and allow any material change in the nature of its business.
- If an event of default with respect to a borrower occurs under its respective credit facility, the lenders will be able to terminate the commitments for the respective borrowers and accelerate the maturity of any loans of the defaulting borrower under the respective credit facility agreement and exercise other rights and remedies.
- Each time funds are borrowed under our credit facility, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to the bank's alternate base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. The borrower is required to pay a commitment fee based on the unused portion of its respective credit facility. The applicable margin and the commitment fee are determined for us by reference to a pricing schedule based on our senior unsecured long-term debt ratings.

Significant financial covenants under the agreement require the ratio of debt to EBITDA (each as defined in the credit agreement) be no greater than 5 to 1, except for the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the ratio of debt to EBITDA is to be no greater than 5.5 to 1.

We are in compliance with these financial covenants as measured at December 31, 2015.

As of February 25, 2016, $475 million is outstanding under our long-term credit facility.

WPZ long-term credit facilities

Prior to their merger both WPZ and ACMP had separate credit facilities that terminated on February 2, 2015.

On February 2, 2015, WPZ along with Transco, Northwest Pipeline, the lenders named therein, and an administrative agent entered into the Second Amended & Restated Credit Agreement with aggregate commitments available of $3.5 billion, with up to an additional $500 million increase in aggregate commitments available under certain circumstances. The maturity date of the credit facility is February 2, 2020. 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 February 2, 2022, under certain circumstances. The agreement allows for swing line loans up to an aggregate amount of $150 million, subject to available capacity under the credit facility, and letters of credit commitments of $1.125 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. On December 18, 2015, WPZ along with Transco, Northwest Pipeline, the lenders named therein and an administrative agent entered into the Amendment No. 1 to Second Amended & Restated Credit Agreement modifying the thresholds specified in the covenant related to the maximum ratio of WPZ's debt to EBITDA.

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

The agreement governing this credit facility 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, enter into certain affiliate transactions, make certain distributions during an event of default, enter into certain restrictive agreements, and allow any material change in the nature of its business.
- If an event of default with respect to a borrower occurs under the credit facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of any loans of the defaulting borrower under the credit facility agreement and exercise other rights and remedies.
- Other than swing line loans, each time funds are borrowed, the borrower must choose whether such borrowing will be an alternate base rate borrowing or a Eurodollar borrowing. If such borrowing is an alternate base rate borrowing, interest is calculated on the basis of the greater of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus one half of 1 percent and (c) a periodic fixed rate equal to the London Interbank Offered Rate (LIBOR) plus 1 percent, plus, in the case of each of (a), (b) and (c), an applicable margin. If the borrowing is a Eurodollar borrowing, interest is calculated on the basis of LIBOR for the relevant period plus an applicable margin. Interest on swingline loans is calculated as the sum of the alternate base rate plus an applicable margin. The borrower is required to pay a commitment fee based on the unused portion of the credit facility. The applicable margin and the commitment fee are determined for each borrower by reference to a pricing schedule based on such borrower's senior unsecured long-term debt ratings.

Significant financial covenants under the agreement require the ratio of debt to EBITDA, each as defined in the credit facility, be no greater than:

- 5.75 to 1, for the quarters ending December 31, 2015, March 31, 2016 and June 30, 2016;
- 5.50 to 1, for the quarters ending September 30, 2016 and December 31, 2016;
- 5.00 to 1, for the quarter ending March 31, 2017 and each subsequent fiscal quarter, except for the the fiscal quarter and the two following fiscal quarters in which one or more acquisitions has been executed, in which case the ratio of debt to EBITDA is to be no greater than 5.5 to 1.00.

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each Transco and Northwest Pipeline. WPZ is in compliance with these financial covenants as measured at December 31, 2015.

As of February 25, 2016, $925 million is outstanding under the long-term credit facility.

WPZ short-term credit facilities

On February 3, 2015, WPZ entered into a short-term $1.5 billion credit facility and terminated it on March 3, 2015. On August 26, 2015, WPZ entered into a credit agreement providing for a $1.0 billion short-term credit facility with a maturity date of August 24, 2016. On December 23, 2015, WPZ's short-term credit facility capacity decreased to $150 million in conjunction with entering into the $850 million term loan.

The agreement governing this credit facility contains the following terms and conditions:

- This facility becomes available when the aggregate amount of outstanding loans under our long-term credit facility plus outstanding commercial paper borrowings reach a total of $3.5 billion.
- Various covenants that limit, among other things, a borrower's and its respective material subsidiaries' ability to grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets in

certain circumstances, enter into certain affiliate transactions, make certain distributions during an event of default, enter into certain restrictive agreements and allow any material change in the nature of its business.

- 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.
- Each time funds are borrowed under the credit facility, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to an alternate base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. The borrower is 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 borrower's senior unsecured long-term debt ratings.

The significant financial covenant requires the ratio of debt to EBITDA, each as defined in the credit agreement, as of the last day of any fiscal quarter for which financial statements have been delivered to be no greater than 6.0 to 1.0. WPZ is in compliance with these financial covenants as measured at December 31, 2015.

Commercial Paper Program

On February 2, 2015, WPZ amended and restated the commercial paper program for the ACMP Merger and to allow a maximum outstanding amount of unsecured commercial paper notes of $3 billion. 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. Proceeds from these notes are used for general partnership purposes, including funding capital expenditures, working capital, and partnership distributions. We classify WPZ's commercial paper outstanding in Current liabilities in the Consolidated Balance Sheet, as the outstanding notes at December 31, 2015 and December 31, 2014, have maturity dates less than three months from the date of issuance. At December 31, 2015, WPZ had $499 million in Commercial paper outstanding at a weighted average interest rate of 0.92 percent and at December 31, 2014, WPZ had $798 million in Commercial paper outstanding at a weighted average interest rate of 0.92 percent.

Cash Payments for Interest (Net of Amounts Capitalized)

Cash payments for interest (net of amounts capitalized) were $1.023 billion in 2015, $681 million in 2014, and $472 million in 2013.

Restricted Net Assets of Subsidiaries

We have considered the guidance in the Securities and Exchange Commission's Regulation S-X related to restricted net assets of subsidiaries. In accordance with Rule 4-08(e) of Regulation S-X, we have determined that certain net assets of our subsidiaries are considered restricted under this guidance and exceed 25 percent of our consolidated net assets. As of December 31, 2015, substantially all of these restricted net assets relate to the net assets of WPZ, which are technically considered restricted under this accounting rule due to terms within WPZ's partnership agreement that govern the partnerships' assets. Our interest in WPZ's net assets that are considered to be restricted at December 31, 2015 was $14 billion.

Leases-Lessee

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

	December 31, 2015 (Millions)
2016	$86
2017	74
2018	56
2019	45
2020	39
Thereafter	119
Total	$419

Total rent expense was $164 million in 2015, $109 million in 2014, and $58 million in 2013 and primarily included in Operating and maintenance expenses and Selling, general, and administrative expenses in the Consolidated Statement of Operations.

Accounting Standards Issued and Adopted

In April 2015, the FASB issued ASU 2015-03 "Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03). ASU 2015-03 simplifies the presentation of debt issuance costs by requiring such costs be presented as a deduction from the corresponding debt liability. Subsequently, in August 2015, the FASB issued ASU 2015-15 "Interest-Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements-Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting" (ASU 2015-15). In ASU 2015-15 the FASB stated that the guidance in ASU 2015-03 did not address the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, and entities are permitted to defer and present debt issuance costs related to line-of-credit arrangements as assets. The standards are effective for financial statements issued for interim and annual reporting periods beginning after December 15, 2015, and require retrospective presentation. Early adoption is permitted. We elected to early adopt these standards for the periods presented. Accordingly, $123 million and $108 million of debt issuance costs as of December 31, 2015 and 2014, respectively, are now reflected as a direct reduction from Long-term debt in our Consolidated Balance Sheet. Debt issuance costs related to our credit facilities are presented in Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet.

Note 15 – Stockholders' Equity

Cash dividends declared per common share were $2.45, $1.9575, and $1.4375 for 2015, 2014, and 2013, respectively.

On June 23, 2014, we issued 61 million shares of common stock in a public offering at a price of $57.00 per share. That amount includes 8 million shares purchased pursuant to the full exercise of the underwriter's option to purchase additional shares. The net proceeds of $3.378 billion were used in July 2014 to finance a portion of the ACMP Acquisition. (See Note 2 – Acquisitions.)

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

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, 2014	$(1)	$31	$(371)	$(341)
Other comprehensive income (loss) before reclassifications	3	(134)	8	(123)
Amounts reclassified from accumulated other comprehensive income (loss)	(3)	—	25	22
Other comprehensive income (loss)	—	(134)	33	(101)
Balance at December 31, 2015	$(1)	$(103)	$(338)	$(442)

Reclassifications out of AOCI are presented in the following table by component for the year ended December 31, 2015:

Component	Reclassifications	Classification
	(Millions)	
Cash flow hedges:		
Energy commodity contracts	$(3)	Product sales
Total cash flow hedges, before income taxes	(3)	
Pension and other postretirement benefits:		
Amortization of prior service cost (credit) included in net periodic benefit cost	(6)	Note 9 – Employee Benefit Plans
Amortization of actuarial (gain) loss included in net periodic benefit cost	46	Note 9 – Employee Benefit Plans
Total pension and other postretirement benefits, before income taxes	40	
Reclassifications before income taxes	37	
Income tax benefit	(15)	Provision (benefit) for income taxes
Reclassifications during the period	$22	

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, 2015, 28 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19 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,

137

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

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. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the ESPP was approved by the stockholders. Offering periods are from January through June and from July through December. Generally, all employees are eligible to participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold. Employees purchased 354 thousand shares at an average price of $28.07 per share during 2015. Approximately 1.5 million shares were available for purchase under the ESPP at December 31, 2015. The plan has been suspended effective January 1, 2016.

Operating and maintenance expenses and Selling, general and administrative expenses include equity-based compensation expense for the years ended December 31, 2015, 2014, and 2013 of $56 million, $44 million, and $37 million, respectively. Income tax benefit recognized related to the stock-based compensation expense for the years ended December 31, 2015, 2014, and 2013 was $21 million, $17 million, and $14 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2015, was $65 million, which does not include the effect of estimated forfeitures of $2 million. Unrecognized stock-based compensation expense is comprised of $4 million related to stock options and $61 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.9 years.

Stock Options

Stock options are valued at the date of award, which does not precede the approval date. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of grant. Stock options generally expire ten years after the grant.

The following summary reflects stock option activity and related information for the year ended December 31, 2015:

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2014	5.8	$25.86	
Granted	1.0	$49.15	
Exercised	(1.1)	$19.30	
Outstanding at December 31, 2015	5.7	$31.51	$15
Exercisable at December 31, 2015	4.0	$25.52	$15

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Total intrinsic value of options exercised	$37	$48	$23

Tax benefits realized on options exercised	$13	$18	$9
Cash received from the exercise of options	$20	$31	$13

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

The weighted-average remaining contractual life for stock options outstanding and exercisable at December 31, 2015, was 5.7 years and 4.4 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:

	2015	2014	2013
Weighted-average grant date fair value of options for our common stock granted during the year, per share	$7.61	$7.50	$5.94
Weighted-average assumptions:			
Dividend yield	4.8 %	4.2 %	4.3 %
Volatility	27.8 %	28.0 %	29.7 %
Risk-free interest rate	1.8 %	2.2 %	1.4 %
Expected life (years)	6.0	6.5	6.5

The 2015 expected dividend yield is based on the 2015 dividend forecast and the grant-date market price of our stock. Expected volatility is based on the average of our peer group 10-year historical volatility adjusted by a ratio of our implied volatility to the average of our peer group's implied volatility. The adjustment is made because the difference in implied volatility between our peer group and us may indicate that we are expected to be more volatile than our peer group average. 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.
Nonvested Restricted Stock Units
The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2015.

Restricted Stock Units Outstanding	Shares	Weighted-Average Fair Value (1)
	(Millions)	
Nonvested at December 31, 2014	3.6	$33.90
Granted	1.4	$40.15
Forfeited	(0.1)	$36.49
Vested	(1.5)	$27.45
Nonvested at December 31, 2015	3.4	$39.38

(1) Performance-based restricted stock units are valued utilizing a Monte Carlo valuation method using measures of total shareholder return. Certain of the performance-based restricted stock units are subject to a holding period of up to two years after the vesting date. Discounts for the restrictions of liquidity were applied to the estimated fair value at the date of the awards and ranged from 5.83 percent to 15.58 percent. The discounts were developed using the Chaffe model and the Finnerty model. 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	2015	2014	2013
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$40.15	$42.79	$30.43
Total fair value of restricted stock units vested during the year ($'s in millions)	$42	$27	$27

Performance-based restricted stock units granted under the Plan represent 40 percent of nonvested restricted stock units outstanding at December 31, 2015. These grants may be earned at the end of the vesting period based on actual

139

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

performance against a performance target. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 500 percent of the original grant amount.

WPZ's Plan Information

During 2014, certain employees of ACMP's general partner received equity-based compensation through ACMP's equity-based compensation program. The fair value of the awards issued was based on the fair market value of the common units on the date of grant. This value is being amortized over the vesting period, which is one to four years from the date of grant. These awards were converted to WPZ equity-based awards in accordance with the terms of the ACMP Merger. No additional grants of restricted common units were awarded through WPZ's equity-based compensation programs in 2015, and no additional grants are expected in the future. Equity-based compensation expense of $29 million and $11 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, 2015 and 2014, respectively. As of December 31, 2015, there was $32 million of unrecognized compensation expense attributable to the outstanding awards, which does not include the effect of estimated forfeitures of $4 million. These amounts are expected to be recognized over a weighted average period of 1.8 years.

The following summary reflects nonvested WPZ restricted common unit activity and related information for the year ended December 31, 2015:

Restricted Common Units Outstanding	Units	Weighted-Average Fair Value
	(Millions)	
Nonvested at December 31, 2014	1.3	$59.35
Adjustment for unit split in ACMP Merger	0.1	$—
Forfeited	(0.1)	$58.05
Vested	(0.1)	$59.28
Nonvested at December 31, 2015	1.2	$55.93

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

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, commercial paper, and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(Millions)				
Assets (liabilities) at December 31, 2015:					
Measured on a recurring basis:					
ARO Trust investments	$67	$67	$67	$—	$—
Energy derivatives assets not designated as hedging instruments	5	5	—	3	2
Energy derivatives liabilities not designated as hedging instruments	(2)	(2)	—	—	(2)
Additional disclosures:					
Notes receivable and other	12	30	10	2	18
Long-term debt, including current portion (1)	(23,987)	(19,606)	—	(19,606)	—
Guarantee	(29)	(16)	—	(16)	—
Assets (liabilities) at December 31, 2014:					
Measured on a recurring basis:					
ARO Trust investments	$48	$48	$48	$—	$—
Energy derivatives assets not designated as hedging instruments	3	3	1	—	2
Energy derivatives liabilities not designated as hedging instruments	(2)	(2)	—	—	(2)
Additional disclosures:					
Notes receivable and other	30	57	—	4	53
Long-term debt, including current portion (1)	(20,779)	(21,131)	—	(21,131)	—
Guarantee	(31)	(27)	—	(27)	—

(1) Excludes capital leases. The carrying value has been reduced by $123 million and $108 million of debt acquisition costs at December 31, 2015 and 2014, respectively. (See Note 14 – Debt, Banking Arrangements, and Leases.)

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, is classified as available-for-sale, 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 (OTC) 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 Other noncurrent liabilities 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, 2015 or 2014.

Additional fair value disclosures

Notes receivable and other: Notes receivable and other consists of various notes, including a receivable related to the sale of certain former Venezuela assets. The disclosed fair value of this receivable is determined by an income approach. We calculated the net present value of a probability-weighted set of cash flows utilizing assumptions based on contractual terms, historical payment patterns by the counterparty, future probabilities of default, our likelihood of using arbitration if the counterparty does not perform, and discount rates. We determined the fair value of the receivable to be $18 million at December 31, 2015. We began accounting for the receivable under a cost recovery model in first-quarter 2015. Subsequently, we received a payment greater than the carrying amount of the receivable, and as a result, the carrying value of this receivable is zero at December 31, 2015. We received another payment in January 2016. We have the right to receive two remaining quarterly cash installments of $15 million plus interest. See Note 5 – Investing Activities for interest income associated with this receivable. The current and noncurrent portions of our receivables in 2015 and 2014 are reported in Accounts and notes receivable, Other current assets and deferred charges, and Regulatory assets, deferred charges, and other, respectively, in the Consolidated Balance Sheet.

Long-term debt: The disclosed fair value of our long-term debt is determined 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.

Guarantee: The guarantee represented in the table consists 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.

To estimate the disclosed fair value of the 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 guarantee is reported in Accrued liabilities in the Consolidated Balance Sheet.

Assets measured at fair value on a nonrecurring basis

We performed an interim assessment of the goodwill associated with our Access Midstream reporting unit as of September 30, 2015, and the annual assessment of goodwill associated with our Northeast G&P and West reporting units as of October 1, 2015. No impairment charges were required following these evaluations.

During the fourth quarter of 2015, we observed a significant decline in the market values of WPZ and comparable midstream companies within the industry. This served to reduce our estimate of enterprise value and increased our estimates of discount rates. As a result, we performed an impairment assessment as of December 31, 2015, of the goodwill associated with these reporting units, all within the Williams Partners segment.

We estimated the fair value of each reporting unit based on an income approach utilizing discount rates specific to the underlying businesses of each reporting unit. These discount rates considered variables unique to each business area, including equity yields of comparable midstream businesses, expectations for future growth, and customer performance considerations. Weighted-average discount rates utilized ranged from approximately 10 percent to 13 percent across the three reporting units.

As a result of the increases in discount rates during the fourth quarter, coupled with certain reductions in estimated future cash flows determined during the same period, the fair values of the Access Midstream and Northeast G&P reporting units were determined to be below their respective carrying values. For these measurements, the book basis of each reporting unit was reduced by the associated deferred tax liabilities. We then calculated the implied fair value of goodwill by performing a hypothetical application of the acquisition method wherein the estimated fair value was allocated to the underlying assets and liabilities of each reporting unit. As a result of these level 3 measurements, we determined that the previously recorded goodwill associated with each reporting unit was fully impaired, resulting in a fourth quarter noncash charge of $1,098 million. For the West reporting unit, the estimated fair value significantly exceeded the carryi