WILLIAMS COMPANIES INC
Form 10-K
February 25, 2011

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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, 2010

or

o **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 o

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 o 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 o

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 o

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. o

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 o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o 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 $10,683,141,499.

The number of shares outstanding of the registrant s common stock outstanding at February 21, 2011 was 586,207,919.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s Definitive Proxy Statement for the Registrant s 2011 Annual Meeting of Stockholders to be held on May 19, 2011, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.
FORM 10-K

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PART IV

DEFINITIONS

We use the following oil and gas measurements in this report:

Barrel means one barrel of petroleum products that equals 42 U.S. gallons.

Bcfe means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Bcf/d means one billion cubic feet per day.

British Thermal Unit or BTU means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

BBtud means one billion BTUs per day.

Dekatherms or Dth or Dt means a unit of energy equal to one million BTUs.

Mbbls/d means one thousand barrels per day.

Mcfe means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Mdt/d means one thousand dekatherms per day.

MMboe means one million barrels of oil equivalent.

MMBtu means one million Btus.

MMBtu/d means one million Btus per day.

MMcf means one million cubic feet.

MMcf/d means one million cubic feet per day.

MMcfe means one million cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMdt means one million dekatherms or approximately one trillion BTUs.

MMdt/d means one million dekatherms per day.

TBtu means one trillion BTUs.

Other definitions:

FERC means Federal Energy Regulatory Commission.

Fractionation means the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane.

LNG means liquefied natural gas; natural gas which has been liquefied at cryogenic temperatures.

NGL means 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 means NGL revenues less Btu replacement cost, plant fuel, transportation and fractionation.

Throughput means 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 requires, 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 Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (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 *http://www.sec.gov*.

Our Internet website is *http://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 integrated natural gas company originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. We were founded in 1908 when two Williams brothers began a construction company in Fort Smith, Arkansas. Today, we primarily find, produce, gather, process and transport natural gas. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Eastern Seaboard, and the province of Alberta in Canada.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

CHANGE IN STRUCTURE AND DIVIDEND INCREASE

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to separate the company into two standalone, publicly traded corporations. The plan calls for the separation of our exploration and production business into a publicly traded company via an initial public offering of up to 20 percent of our interest in the third quarter of 2011. We intend to complete the offering so that it preserves our ability to complete a tax-free spinoff of our remaining ownership in the exploration and production business to Williams shareholders in 2012, after which Williams would continue as a premier natural gas infrastructure company. We retain the discretion to determine whether and when to execute the spinoff.

Additionally, we intend to increase the quarterly dividend paid to our shareholders, with an initial increase of 60 percent (to $0.20 per share), for the first quarter of 2011 payable in June 2011.

Management believes these actions will serve to enhance the growth potential and overall valuation of our assets.

FINANCIAL INFORMATION ABOUT SEGMENTS

See *Item 8 Financial Statements and Supplementary Data Notes to Consolidated Financial Statements Note 18* for information with respect to each segment s revenues, profits or losses and total assets.

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities in 2010 were primarily operated through the following business segments:

Williams Partners comprised of our master limited partnership Williams Partners L.P. (WPZ), which includes gas pipeline and domestic midstream businesses. The gas pipeline business includes interstate natural gas pipelines and pipeline joint venture investments, and the midstream business provides natural gas gathering, treating and processing services; NGL production, fractionation, storage, marketing and transportation; deepwater production handling and crude oil transportation services and is comprised of several wholly owned and partially owned subsidiaries and joint venture investments.

Exploration & Production produces, develops, and manages natural gas and oil primarily located in the Rocky Mountain, Northeast and Mid-Continent regions of the United States and is comprised of several wholly owned and partially owned subsidiaries including Williams Production Company, LLC and Williams Production RMT Company, LLC. This segment also includes our 69 percent equity interest in Apco Oil and Gas International Inc., as well as gas marketing services which manage our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.

Other includes other business activities that are not operating segments, primarily our Canadian midstream and domestic olefins operations and a 25.5 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream), as well as corporate operations.

This report is organized to reflect this structure.

Due to expected future growth in our Canadian midstream and domestic olefins operations, we are considering reporting these businesses as a separate segment beginning in the first quarter of 2011.

Detailed discussion of each of our business segments follows.

Williams Partners

Gas Pipeline Business

Williams Partners owns and operates a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,800 TBtu of natural gas and peak-day delivery capacity of approximately 13 MMdt of natural gas. Our gas pipeline businesses consist primarily of Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline). Our gas pipeline business also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream. The gas pipeline businesses contributed revenues of approximately 28 percent, 35 percent and 28 percent of Williams Partners revenues in 2010, 2009, and 2008, respectively. During third quarter 2010, Williams Partners L.P. completed a merger with Williams Pipeline Partners L.P. (WMZ). All of WMZ s common and subordinated units have been extinguished and WMZ is wholly owned by Williams Partners. WMZ has been delisted and is no longer publicly traded.

Transco

Transco is an interstate natural gas transportation company that owns and operates a 10,000-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., New York, New Jersey and Pennsylvania.

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Pipeline system and customers

At December 31, 2010, Transco s system had a mainline delivery capacity of approximately 4.9 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.9 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.8 MMdt 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 1.5 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, 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 storage services and interruptible transportation services under short-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 billion cubic feet of gas. At December 31, 2010, our customers had stored in our facilities approximately 154 Bcf of natural gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, a LNG storage facility with 4 billion cubic feet 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.

Transco expansion projects

The pipeline projects listed below were completed during 2010 or are future significant pipeline projects for which Transco has customer commitments.

Mobile Bay South

The Mobile Bay South Expansion Project involved the addition of compression at Transco s Station 85 in Choctaw County, Alabama, to allow Transco to provide firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In May 2009, Transco received approval from the Federal Energy Regulatory Commission (FERC). The capital cost of the project was $32 million. The project was placed into service in May 2010 and increased capacity by 254 Mdt/d.

Mobile Bay South II

The Mobile Bay South II Expansion Project involves the addition of compression at Transco s Station 85 in Choctaw County, Alabama, and modifications to existing facilities at Transco s Station 83 in Mobile County, Alabama, to allow Transco to provide additional firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In July 2010 Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $35 million, and it will increase capacity by 380 Mdt/d. Transco plans to place the project into service by May 2011.

85 North

The 85 North Expansion Project involves an expansion of Transco s existing natural gas transmission system from Station 85 in Choctaw County, Alabama, to various delivery points as far north as North Carolina. In September 2009, Transco received approval from the FERC. The capital cost of the project is estimated to be approximately $236 million, and it will increase capacity by 309 Mdt/d. The first phase for 90 Mdt/d, was placed into service in July 2010, and the second phase is expected to be placed into service in May 2011.

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Mid-South

The Mid-South Expansion Project involves an expansion of Transco s mainline from Station 85 in Choctaw County, Alabama, to markets as far downstream as North Carolina. In October 2010 Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $219 million. Transco plans to place the project into service in phases in September 2012 and June 2013, and it will increase capacity by 225 Mdt/d.

Mid-Atlantic Connector Project

The Mid-Atlantic Connector Project involves an expansion of Transco s mainline from an existing interconnection in North Carolina to markets as far downstream as Maryland. In November 2010 Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $55 million. Transco plans to place the project into service in November 2012, and it will increase capacity by 142 Mdt/d.

Rockaway Delivery Lateral Project

The Rockaway Delivery Lateral Project involves the construction of a three-mile offshore lateral to a distribution system in New York. Transco anticipates filing an application with the FERC in the fourth quarter of 2011. The capital cost of the project is estimated to be approximately $159 million. Transco plans to place the project into service as early as November 2013, and its capacity will be 647 Mdt/d.

Northeast Supply Link Project

The Northeast Supply Link Project involves an expansion of Transco s existing natural gas transmission system from the Marcellus Shale production region on the Leidy Line to various delivery points in New York and New Jersey. Transco anticipates filing an application with the FERC in the fourth quarter of 2011. The capital cost of the project is estimated to be approximately $341 million. Transco plans to place the project into service in November 2013, and it will increase capacity by 250 Mdt/d.

Northwest Pipeline

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system 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 California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2010, Northwest Pipeline s system, having long-term firm transportation agreements including peaking service of approximately 3.8 Bcf of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 477,000 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 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 storage service 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 gas storage capacity of 13.2 Bcf of natural gas, which is substantially utilized for third-party natural gas, and firm

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delivery capability of approximately 700 MMcf/d enable Northwest Pipeline to provide storage services to its customers and to balance daily receipts and deliveries.

Northwest Pipeline expansion project

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming as well as an upgrade to an existing Vernal, Utah compressor station. The total estimated cost of the project is approximately $50 million. We placed the project in service in November 2010 with an increase in capacity of 150 Mdt/d.

Gulfstream

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Williams Partners owns, through a subsidiary, a 24.5 percent interest in Gulfstream while we own a 25.5 percent interest through a subsidiary. Spectra Energy Corporation, through its subsidiary, and Spectra Energy Partners, LP, own the additional 50 percent interest. Williams Partners shares operating responsibilities for Gulfstream with Spectra Energy Corporation.

Gulfstream expansion projects

The Gulfstream Phase V expansion involves the addition of compression to provide 35 Mdt/d of firm capacity by April 2011. The estimated capital cost of this expansion is approximately $44 million with Williams Partners share being 24.5 percent of such cost.

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 Colorado, New Mexico, Wyoming, the Gulf of Mexico and Pennsylvania. The primary businesses natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer.

Key variables for this business will continue to be:

- 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;
- Prices impacting commodity-based processing activities.

The midstream business revenue contributed approximately 72 percent, 66 percent and 72 percent of Williams Partners revenues in 2010, 2009 and 2008, respectively.

One of our midstream customers, ONEOK Hydrocarbon LP, accounted for 10 percent of our consolidated revenues in 2010. These revenues were generated by our NGL marketing business. There were no customers for which our sales exceeded 10 percent of our consolidated revenues in 2009 and 2008.

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. In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Processing and treating plants remove water vapor, carbon dioxide and other contaminants and extract the NGLs. 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, iso-butane and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Although a significant portion of Williams Partners gas processing services are performed for a volumetric-based fee, a portion of our gas processing agreements are commodity-based and include two distinct types of commodity exposure. The first type includes keep-whole processing agreements whereby we own the rights to the value from NGLs recovered at our plants and we have the obligation to replace the lost heating value with natural gas. Under these agreements, we are exposed to the spread between NGL prices and natural gas prices. The second type consists of percent-of-liquids agreements whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these agreements, we are only exposed to NGL price movements. NGLs we retain in connection with both of these types of processing agreements are referred to as our equity NGL production. 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.

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 2010, these operations gathered and processed gas for approximately 215 gas gathering and processing customers. Williams Partners top 6 gathering and processing customers, one of which is an affiliate, accounted for approximately 50 percent of our gathering and processing revenue.

In addition to natural gas assets, Williams Partners owns and operates four deepwater crude oil pipelines and owns two production platforms serving the deepwater in the Gulf of Mexico. The crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of its marketing revenues are recognized from purchase and sale arrangements whereby the oil that Williams Partners transports is purchased and sold as a function of the same index-based price. Williams Partners 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.

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. Also, the gathering and processing facilities in the San Juan and Piceance basins handle approximately 92 percent of our Exploration & Production segment s equity production in these basins. The San Juan basin, southwest Wyoming and Willow Creek systems deliver residue gas volumes into Northwest Pipeline s interstate system in addition to third-party interstate systems.

Onshore region gathering, processing and treating

Williams Partners owns and/or operates gas gathering, processing and treating assets within the states of Wyoming, Colorado, New Mexico and Pennsylvania.

In the Rocky Mountain area, the assets include:

- Approximately 3,500 miles of gathering pipelines with a capacity of nearly 1 Bcf/d and over 4,000 receipt points serving the Wamsutter and southwest Wyoming areas in Wyoming;

Opal and Echo Springs processing plants with a combined daily inlet capacity of over 2.2 Bcf/d and NGL processing capacity of nearly 125 Mbbls/d, including the addition of a fourth cryogenic processing train at the Echo Springs plant which began processing in the fourth quarter of 2010.

In the Four Corners area, the assets include:

Approximately 3,800 miles of gathering pipelines with a capacity of nearly 2 Bcf/d and approximately 6,500 receipt points serving the San Juan basin in New Mexico and Colorado;

Ignacio, Kutz and Lybrook processing plants with a combined daily inlet capacity of 765 MMcf/d and NGL processing capacity of approximately 40 Mbbls/d. The Ignacio plant also has the capacity to produce slightly more than 1 Mbbls/d of liquefied natural gas (LNG);

Milagro and Esperanza natural gas treating plants, which remove carbon dioxide but do not extract NGLs, with a combined daily inlet capacity of 750 MMcf/d. At our Milagro facility, we also use gas-driven turbines to produce approximately 60 mega-watts per day of electricity which we primarily sell into the local electrical grid.

In the Piceance basin in Colorado, the assets include:

The Willow Creek processing plant, a 450 MMcf/d cryogenic natural gas processing plant in western Colorado s Piceance basin, designed to recover 30 Mbbls/d of NGLs. The plant is currently operating at its designed inlet capacity. In the current processing arrangement with our Exploration & Production segment, Williams Partners receives a volumetric-based processing fee and a percent of the NGLs extracted.

Approximately 150 miles of gathering pipeline and the Parachute Plant Complex along with three other treating facilities with a combined processing capacity of 1.2 Bcf/d, acquired in the fourth quarter of 2010 from Exploration & Production.

Parachute Lateral, a 38-mile, 30-inch diameter line transporting gas from the Parachute area to the Greasewood hub and White River hub in northwest Colorado. The Willow Creek plant processes gas flowing through the Parachute Lateral.

PGX pipeline delivering NGLs from our Exploration & Production segment s existing Parachute area processing plants to a major NGL transportation pipeline system.

In the Appalachian basin in Pennsylvania, the assets include:

Approximately 75 miles of gathering pipelines and two compressor stations in Susquehanna County, Pennsylvania in the Marcellus Shale, acquired in the fourth quarter of 2010. Williams Partners has agreed to a new long-term dedicated gathering agreement with the seller for its production in the northeast Pennsylvania area of the Marcellus Shale. The acquired system will connect into the Transco pipeline with our 33-mile, 24-inch diameter Springville gathering pipeline. Construction on the Springville pipeline is expected to begin in the first quarter of 2011 and be completed during 2011.

Gulf region gathering, processing and treating

Williams Partners   owns and/or operates gas gathering and processing assets and crude oil pipelines primarily within the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama. This includes:

- Nearly 800 miles of onshore and offshore natural gas gathering pipelines with a combined capacity of approximately 3.7 Bcf/d, including:
  - The 115-mile deepwater Seahawk gas pipeline in the western Gulf of Mexico, flowing into the Markham processing plant and serving the Boomvang and Nansen field areas;

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The 105-mile deepwater Perdido Norte gas pipeline in the western Gulf of Mexico, which began transporting gas in the third quarter of 2010 from a third-party producers floating production facility in to the Seahawk gathering system, which flows into Williams Partners Markham processing plant;

The 139-mile Canyon Chief gas pipeline, including the Blind Faith extension in the eastern Gulf of Mexico, flowing into the Mobile Bay processing plant and serving the Devils Tower, Triton, Goldfinger, Bass Lite and Blind Faith fields;

Mobile Bay and Markham processing plants with a combined daily inlet capacity of 1.2 Bcf/d and NGL handling capacity of 75 Mbbls/d, including the 2010 expansion of the Markham plant to accommodate production volumes from the Perdido Norte gas pipeline;

Canyon Station production platform, which brings natural gas to specifications allowable by major interstate pipelines but does not extract NGLs, with a daily inlet capacity of 500 MMcf/d;

Four deepwater crude oil pipelines with a combined length of nearly 400 miles and capacity of 475 Mbbls/d including:

BANJO pipeline running parallel to the Seahawk gas pipeline delivering production from two producer-owned spar-type floating production systems; and delivering production to the shallow-water platform at Galveston Area Block A244 (GA-A244) and then onshore through the Hoover Offshore Oil Pipeline System (HOOPS);

Perdido Norte pipeline running parallel to the Perdido Norte gas pipeline which began transporting oil in the third quarter of 2010 from a third-party producers floating production facility and then onshore through HOOPS;

Alpine pipeline in the central Gulf of Mexico, serving the Gunnison field, and delivering production to GA-A244 and then onshore through HOOPS under a joint tariff agreement;

Mountaineer pipeline, including the Blind Faith extension, which connects to similar production sources as our Canyon Chief pipeline, ultimately delivering production to a terminal in Plaquemines Parish, Louisiana;

Devils Tower production platform located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama and serving production from the Devils Tower, Triton, Goldfinger and Bass Lite fields. Located in 5,610 feet of water, it is one of the world s deepest dry tree spars. The platform, which is operated by another party, is capable of handling 210 MMcf/d of natural gas and 60 Mbbls/d of oil.

NGL marketing services

In addition to Williams Partners gathering and processing operations, we market NGL products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets equity NGLs from the production at its processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of its fee-based processing customers, and the NGL volumes owned by Discovery Producer Services LLC (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, Williams Partners may purchase products in the spot market for resale. The majority of sales are based on supply contracts of one year or less in duration.

Other Partially Owned Operations

Fractionation and Storage

Williams Partners owns interests in and/or operates NGL fractionation and storage assets. These assets include a 50 percent interest in an NGL fractionation facility near Conway, Kansas with capacity of slightly more than 100 Mbbls/d and a 31.45 percent interest in another fractionation facility in Baton Rouge, Louisiana with a capacity of 60 Mbbls/d. Williams Partners also fully owns approximately 20 million barrels of NGL storage capacity in central Kansas near Conway.

Overland Pass Pipeline

In September 2010, Williams Partners completed the $424 million acquisition of an additional 49 percent ownership interest in Overland Pass Pipeline (OPPL), which increased our ownership interest to 50 percent. As long as we retain a 50 percent ownership interest in OPPL, we have the right to become operator. We have notified our partner of our intent to operate and are currently working on an early 2011 transition. OPPL includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Joules basins in Colorado, respectively. Williams Partners 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 shipping agreement.

Discovery

Williams Partners owns a 60 percent equity interest in and operates 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 an offshore natural gas gathering and transportation system in the Gulf of Mexico.

Laurel Mountain

Williams Partners owns a 51 percent interest in a joint venture, Laurel Mountain Midstream LLC (Laurel Mountain), in the Marcellus Shale located in western Pennsylvania. Laurel Mountain s assets, which we operate, include a gathering system of approximately 1,000 miles of pipeline with a fourth quarter 2010 average throughput of approximately 125 MMcf/d. Laurel Mountain has a long-term, dedicated, volumetric-based fee agreement, with some exposure to natural gas prices, to gather the production of its joint venture partner s production in the northeast Pennsylvania area of the Marcellus Shale. Construction began in 2010 on numerous new pipeline segments and compressor stations, the largest of which is the Shamrock compressor station. The Shamrock compressor station will have an initial capacity of 60 MMcf/d, expandable to 350 MMcf/d, which will likely be the largest central delivery point out of the Laurel Mountain system.

Aux Sable

Williams Partners also owns a 14.6 percent equity interest in Aux Sable Liquid Products 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 92 Mbbls/d of extracted liquids into NGL products.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2010	**2009**	**2008**
Volumes:(1)			
Gathering (Tbtu)(3)	1,262	1,370	1,361
Plant inlet natural gas (Tbtu)	1,424	1,342	1,311

NGL production (Mbbls/d)(2)	174	164	154
NGL equity sales (Mbbls/d)(2)	80	80	80
Crude oil gathering (Mbbls/d)(2)	94	109	70

(1) Excludes volumes associated with partially owned assets such as our Discovery and Laurel Mountain investments that are not consolidated for financial reporting purposes.

(2) Annual average Mbbls/d.

(3) Amounts have been recast to reflect the November 2010 acquisition of certain gathering and processing assets in Colorado s Piceance basin from Exploration & Production.

Exploration & Production

Our Exploration & Production segment includes natural gas and oil development, production and gas marketing activities primarily located in the Rocky Mountain (primarily Colorado, North Dakota, New Mexico, and Wyoming), Northeast (Pennsylvania), and Mid-Continent (Oklahoma and Texas) regions of the United States. We specialize in production from tight-sands and shale formations and coal bed methane (CBM) reserves in the Piceance, Appalachian, Williston, San Juan, Powder River, Fort Worth, Green River and Arkoma basins. Almost 97 percent of our domestic proved reserves are natural gas. We also have international oil and gas interests, which include a 69 percent equity interest in Apco Oil and Gas International Inc., an oil and gas exploration and production company with operations in South America. If combined with our domestic proved reserves, our international interests would make up approximately 5 percent of our total proved reserves. Considering this, the reserves information included in this section relates only to our domestic activity. The gas marketing activities include transporting, scheduling, selling and hedging equity natural gas production as well as managing various natural gas related contracts such as transportation, storage and related hedges not utilized for our equity production. Additionally, Exploration & Production s marketing group procures all fuel and shrink requirements and manages transportation and hedging activities in support of our midstream business.

Our strategy is to continue to drill our existing proved undeveloped reserves, which comprise approximately 42 percent of proved reserves, and to drill in areas of probable and possible reserves in order to add to our proved reserves. Our current proved, probable, and possible reserves inventory provides us with strong capital investment opportunities for many years into the future.

Oil and Gas Reserves

The following table outlines our estimated net proved reserves expressed on a gas equivalent basis for the reporting periods December 31, 2010, 2009 and 2008. Proved reserves for 2010 and 2009 were prepared under rules issued by the SEC on January 14, 2009. We prepare our own reserves estimates and the majority of our December 31, 2010 reserves were audited by Netherland, Sewell & Associates (NSAI) or Miller and Lents, Ltd (M&L). Proved reserves information is reported as gas equivalents, since oil volumes are insignificant in the three years shown below. Reserves for 2010 are approximately 97 percent natural gas. Reserves are more than 99 percent natural gas for 2009 and 2008. Oil reserves increased to approximately 3 percent of total proved reserves in 2010 as a result of a fourth quarter acquisition of undeveloped acreage and producing properties located in the Williston basin.

Summary of oil and gas reserves:

	December 31,		
	2010	2009	2008
		(Bcfe)(1)	
Proved developed reserves	2,498	2,387	2,456
Proved undeveloped reserves	1,774	1,868	1,883
Total proved reserves	4,272	4,255	4,339

(1) Gas equivalents are calculated using a ratio of 6 mcf of gas to 1 barrel of oil.

Basin	Proved Reserves December 31, 2010 (Bcfe)
Piceance	2,927
Powder River	348
San Juan	554
Fort Worth	196
Appalachian	28
Williston	136
Other	83
Total	4,272

We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than with the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC.

The 2010 year-end proved reserves were derived using the 12-month average, first-of-the-month Henry Hub spot price of $4.38 per MMbtu, adjusted for locational price differentials. During 2010, we added 508 Bcfe of net additions to our proved reserves through drilling 1,162 gross wells at a capital cost of approximately $988 million.

Reserves estimation process

Our reserves are estimated by deterministic methods by an appropriate combination of production performance analysis and volumetric techniques. The proved reserves for economic undrilled locations are estimated by analogy or volumetrically from offset developed locations. Reservoir continuity and lateral persistence of our tight-sands, shale and CBM reservoirs is established by combinations of subsurface analysis, 2D and 3D seismic, and pressure data. Understanding reservoir quality may be augmented by core samples analysis.

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate by providing supporting information such as pricing, capital costs, expenses, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our reserves analysis department. The reserves analysis department s responsibilities also include performing an internal review of reserves data for reasonableness and accuracy, working with the third-party consultants and the asset teams to successfully complete the third-party reserves audit, finalizing the year-end reserves report, and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. Early in the year, we begin with a review of the existing internal processes and controls to identify where improvements can be made from the prior year s reporting cycle. Later in the year, the reserves staffs from the asset teams submit their preliminary reserves data to the reserves analysis department. After review by the reserves analysis department, the data is submitted to our third party engineering consultants, NSAI and M&L, to begin their audits. After this point, reserves data, analysis and further review are conducted and iterated between the asset teams, reserves analysis department and our third party engineering consultants. In early December, reserves are reviewed with senior management. The process concludes when all parties agree upon the reserve estimates and audit tolerance is achieved.

The reserves estimates resulting from our process are subjected to both internal and external controls to promote transparency and accuracy of the year-end reserves estimates. Our internal reserves analysis team is independent and does not work within an asset team or report directly to anyone on an asset team. The reserves analysis department provides detailed independent review and extensive documentation of the year-end process. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated. The compensation of our reserves analysis team is not linked to reserves additions or revisions.

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Approximately 93 percent of our total year-end 2010 domestic proved reserves estimates were audited by NSAI. When compared on a well-by-well basis, some of our estimates are greater and some are less than the estimates of NSAI. However, in the opinion of NSAI, the estimates of our proved reserves are in the aggregate reasonable and have been prepared in accordance with principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2010 reserves estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. The report of NSAI is included in Exhibit 99.1 to this Form 10-K.

In addition, reserves estimates related to properties associated with the former Williams Coal Seam Gas Royalty Trust were audited by M&L. These properties represent approximately 1 percent of our total domestic proved reserves estimates. The report of M&L is included in Exhibit 99.2 to this Form 10-K.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third- party reserves audit is the Director of Reserves and Production Services. The Director s qualifications include 28 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in Physical Sciences from the University of Houston, and membership in the American Association of Petroleum Geologists and The Society of Petroleum Engineers.

Proved undeveloped reserves (PUDs)

The majority of our reserves is concentrated in unconventional tight-sands, shale and coal bed gas reservoirs. We use available geoscience and engineering data to establish drainage areas and reservoir continuity beyond one direct offset from a producing well, which provides additional proved undeveloped reserves. Inherent in the methodology is a requirement for significant well density of economically producing wells to establish reasonable certainty. In fields where producing wells are less concentrated, only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification. No new technologies were used to assign proved undeveloped reserves.

At December 31, 2010, our proved undeveloped reserves were 1,774 Bcfe a decrease of 94 Bcfe over our December 31, 2009 proved undeveloped reserves estimate of 1,868 Bcfe. During 2010, 280 Bcfe of our December 31, 2009 proved undeveloped reserves were converted to proved developed reserves. An additional 129 Bcfe was added due to the development of unproved locations. We have reclassified a net 253 Bcfe from proved to probable reserves attributable to locations not expected to be developed within five years. This amount is predominantly in the Piceance basin where the company has a large inventory of drilling locations. The downward revision has been offset by the addition of 342 Bcfe of new proved undeveloped drilling locations.

All proved undeveloped locations are scheduled to be spud within the next five years. Our five-year forecast indicates increasing capital to allow for the addition of rigs in years 2013-2015 in the Piceance basin. Our undeveloped estimate contains 91 Bcfe of aging PUDs. The majority of these are scheduled to be spud by year-end 2011.

Oil and Gas Properties and Production, Production Prices, and Production Costs

The following table summarizes our domestic sales volumes for the years indicated:

	2010	2009	2008
		(Bcfe)	

Piceance	245.9	254.6	237.7
Powder River	83.8	88.9	83.6
San Juan	51.5	53.1	52.8
Fort Worth	21.5	25.2	16.6
Appalachian	1.8	0.1	
Williston	0.1		
Other	8.5	9.6	9.7
Total net production sold	413.1	431.5	400.4

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The following table summarizes our domestic price and cost information for the years indicated and has been recast for the sale of certain of our gathering and processing assets in the Piceance basin to Williams Partners in November 2010:

	2010	2009 ($/Mcfe)	2008
Average production costs excluding production taxes(1)	$ 0.59	$ 0.50	$ 0.56
Average sales price(2)	$ 4.42	$ 3.42	$ 6.95
Realized gain from hedging	$ 0.81	$ 1.43	$ 0.09
Realized Average Price	$ 5.23	$ 4.85	$ 7.04

(1) Includes lease and other operating expense and facility operating expense.

(2) Not reduced for gathering, processing, and transportation paid to affiliates and third parties of $1.02 in 2010, $0.79 in 2009, and $0.71 in 2008.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2010, 2009, and 2008.

The following table summarizes domestic drilling activity by number and type of well for the periods indicated:*

	2010		2009		2008	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance	398	360	349	303	687	624
Powder River	531	242	233	95	702	324
San Juan	43	15	77	39	95	37
Fort Worth	39	36	43	41	58	51
Appalachian	8	3	8	4	n/a	n/a
Williston			n/a	n/a	n/a	n/a
Other	138	2	165	4	240	14
Productive exploration			3	1	4	2
Nonproductive, including exploration	5	3	4	1	1	
Total	1,162	661	882	488	1,787	1,052

* We use the terms gross to refer to all wells or acreage in which we have at least a partial working interest and net to refer to our ownership represented by that working interest. All of the wells drilled were natural gas wells.

In 2010, there were 5 gross nonproductive development wells and 3 net nonproductive development wells. Total gross operated wells drilled were 656 in 2010, 472 in 2009, and 1,125 in 2008.

Present Activities

At December 31, 2010, we had 27 gross (16 net) wells in the process of being drilled.

Delivery Commitments

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance basin. The Piceance, being our largest producing basin, holds ample reserves to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of gas

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is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure.

Purchase Commitments

In connection with a gathering agreement entered into by Williams Partners with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu/d of natural gas priced at market prices from the same third party. Purchases under the 12-year contract are expected to begin in the third quarter of 2011. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Oil and Gas Properties, Wells, Operations, and Acreage

The table below summarizes 2010 productive wells by area:*

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance	3,923	3,587		
Powder River	6,404	2,884		
San Juan	3,267	881		
Fort Worth	286	233		
Appalachian	14	6		
Williston			19	13
Other	1,340	299		
Total	15,234	7,890	19	13

* We use the term gross to refer to all wells or acreage in which we have at least a partial working interest and net to refer to our ownership represented by that working interest.

At December 31, 2010, there were 181 gross and 105 net producing wells with multiple completions.

The following table summarizes our leased acreage as of December 31, 2010:

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance	133,428	102,835	157,017	108,165	290,445	211,000
Powder River	551,113	250,179	399,869	175,371	950,982	425,550
San Juan	237,587	119,422	2,100	1,576	239,687	120,998
Fort Worth	28,876	21,173	12,306	8,309	41,182	29,482
Appalachian	1,828	914	108,023	98,387	109,851	99,301
Williston	16,178	13,483	229,640	190,148	245,818	203,631

Other	120,538	60,559	199,077	118,734	319,615	179,293
Total	1,089,548	568,565	1,108,032	700,690	2,197,580	1,269,255

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2010, we operated an average of 11 drilling rigs in the basin. This area has 1,567 undrilled proved locations in inventory. During 2010, an average of approximately 6.3 million gallons of NGLs were recovered each month at plants now owned and operated within Williams Partners, which were marketed separately from the residue natural gas.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado. We provide a significant amount of equity production that is gathered and/or processed by Williams Partners facilities in the San Juan basin.

Fort Worth basin

The Fort Worth basin is located in north central Texas where we drill horizontally into the Barnett Shale.

Appalachian basin

The Appalachian basin acreage is primarily located in northeastern Pennsylvania where we apply horizontal drilling in the Marcellus Shale. We have continued to expand our position since our entry into the basin in 2009.

Williston basin

The Williston basin acreage is located in North Dakota and Montana. Our focus in the basin is in North Dakota s Bakken/Three Forks oil play where we have a 89,420 net acreage position, of which approximately 85,800 were acquired in December 2010 and are on the Fort Berthold Indian Reservation.

Other properties

Other properties are primarily comprised of interests in the Arkoma basin in southeastern Oklahoma. Also included are exploration activity and other miscellaneous activity.

Hedging Activity

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in *Management s Discussion and Analysis of Financial Condition and Results of Operations Exploration & Production*, included in Item 7 of this Form 10-K

Acquisitions & Divestitures

During the second quarter of 2010, we entered into an agreement to acquire additional Appalachian leasehold acreage positions and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions nearly double our acreage holdings in the Marcellus Shale and closed in July for $599 million, including closing adjustments.

During 2010, we also spent a total of $164 million to acquire additional unproved leasehold acreage positions in the Marcellus Shale.

In October 2010, we exercised our right under the Williams Coal Seam Gas Royalty Trust Agreement to acquire the royalty interests for $22 million, including closing adjustments upon termination of the the Trust. Prior to the purchase, the Trust owned net profits interests in certain proved coal seam gas properties owned by Williams Production Company, LLC (WPC) and located in the San Juan basin.

In November 2010, we sold certain of our gathering and processing assets in Colorado s Piceance basin to Williams Partners for $702 million in cash and approximately 1.8 million common units. The assets include the Parachute Plant Complex, three other treating facilities with a combined processing capacity of 1.2 Bcf/d, and a gathering system with approximately 150 miles of pipeline. There are more than 3,300 wells connected to the gathering system, which includes pipelines ranging up to 30-inch trunk lines. The transaction also includes a life-of-lease dedication from Exploration & Production.

In December 2010, we acquired a company that holds a major acreage position (approximately 85,800 net acres and includes 19 producing wells) in North Dakota s Bakken Shale oil play (Williston basin) that will diversify our interests into light, sweet crude oil production. The purchase price was approximately $949 million, including closing adjustments.

Other

Domestic olefins

In the Gulf of Mexico region, we own a 5/6 interest in and are the operator of an NGL light-feed olefins cracker in Geismar, Louisiana, with a total production capacity of 1.35 billion pounds of ethylene and 90 million pounds of propylene per year. Our feedstocks for the cracker are ethane and propane; as a result, we 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. Additionally, we own a refinery grade propylene splitter and associated pipeline with 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 we are 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. Our olefins business also operates an ethylene storage hub at Mont Belvieu using leased third-party underground storage wells.

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

Canadian midstream

Our Canadian operations include an oil sands off-gas processing plant located near Ft. McMurray, Alberta, and an olefin fractionation facility and a butylene/butane splitter facility, both of which are located at Redwater, Alberta, which is near Edmonton, Alberta. We operate the Ft. McMurray area processing plant, while another party operates the Redwater facilities on our behalf. The butylene/butane splitter was completed and placed into service in August 2010. Our Ft. McMurray area facilities extract liquids from the off-gas produced by a third-party oil sands bitumen upgrading process. Our arrangement with the third-party upgrader is a keep-whole type where we remove a mix of NGLs and olefins from the off-gas and return the equivalent heating value back in the form of natural gas. We fractionate, treat, store, terminal and sell the propane, propylene, butane, butylene and condensate recovered from this process. Our commodity price exposure 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 treater/processor of oil sands upgrader off-gas. Our extraction of liquids from upgrader off-gas streams allows the upgraders to burn cleaner natural gas streams and reduces their overall air emissions.

The Ft. McMurray extraction plant has processing capacity of 111 MMcf/d with the ability to recover in excess of 17 Mbbls/d of olefin and NGL products. Our Redwater fractionator has a liquids handling capacity of 18 Mbbls/d. The new butylene/butane splitter, which has a production capacity of 3.7 Mbbls/d of butylene and 3.7 Mbbls/d of normal butane, further fractionates the butylene/butane mix product produced at our Redwater fractionators into separate butylene and butane products, which receive higher values and are in greater demand. Our products are sold within Canada and the United States.

Canadian expansion project

Construction began in 2010 on a 261-mile, 12-inch diameter Canadian pipeline which will transport recovered NGLs and olefins from our processing plant in Ft. McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional NGLs and olefins from our existing operations as well as from other NGLs and olefins produced from oil sands off-gas. The project will be constructed using cash previously generated from Canadian and other international projects. We anticipate an in-service date in 2012.

Other

Considering the deteriorating circumstances in Venezuela, in 2009 we fully impaired our $75 million investment in Accroven SRL, a Venezuelan operation, which included two 400 MMcf/d NGL extraction plants, a 50 Mbbls/d NGL fractionation plant and associated storage and refrigeration facilities. (See Note 2 of Notes to Consolidated Financial Statements.) In June of 2010, we sold our 50 percent interest in Accroven to the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing and another $30 million was received in August 2010. The remainder is due in six quarterly payments beginning October 31, 2010. The first quarterly payment of $11 million was received in January 2011 and will be recognized as income in 2011. We will continue to recognize the resulting gain as cash is received. Accroven was not part of our operations that were expropriated by the Venezuelan government in May 2009.

Operating statistics

The following table summarizes our significant operating statistics for Other:

	2010	2009	2008
Volumes:			
Canadian NGL equity sales (Mbbls/d)	8	8	7
Olefin (ethylene and propylene) sales (millions of pounds)	1,529	1,728	1,605

Additional Business Segment Information

Our ongoing business segments are accounted for as continuing operations in the accompanying financial statements and notes to financial statements included in Part II.

Operations related to certain assets in Discontinued Operations have been reclassified from their traditional business segment to Discontinued Operations in the accompanying financial statements and notes to 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 and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, interest payments from subsidiaries on cash advances and, if needed, external financings, sales of master limited partnership units to the public, and net proceeds from asset sales. The amount of dividends available to us from subsidiaries largely depends upon each subsidiary s earnings and operating capital requirements. The terms of certain of our 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. In support of our energy commodity activities, primarily conducted through gas marketing services which is included within our Exploration & Production segment, our counterparties require us to provide various forms of credit support such as margin, adequate assurance amounts and pre-payments for gas supplies. Our pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

Williams Partners

Gas Pipeline Business. Williams Partners gas pipeline s 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, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its 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. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, and the Pipeline Safety Improvement Act of 2002, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. 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.

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.

Pipeline Integrity Regulations

For Williams Partners gas pipeline business, Transco and Northwest Pipeline have developed an Integrity Management Plan that we believe meets the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (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 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 timeframes. In meeting the integrity regulations, Transco and Northwest Pipeline have identified high consequence areas and developed baseline assessment plans. Transco and Northwest Pipeline are on schedule to complete the required assessments within required timeframes. Currently, Transco and Northwest Pipeline estimate the cost to complete the required initial assessments over the period from 2011 and 2012 and associated remediation will be primarily capital in nature and range between $80 million and $110 million for Transco and between $50 million and $60 million for Northwest Pipeline. Ongoing periodic reassessments and initial assessments of any new high consequence areas will be completed within the timeframes 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, and, therefore, recoverable through Transco s and Northwest Pipeline s rates.

Midstream Business. For Williams Partners midstream business, onshore gathering is subject to regulation by states in which we operate and offshore gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Of the states where the midstream business gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. 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.

The midstream business also owns interests in and operates 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. 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.

The midstream business owns an interest in, and is expected to become the operator in 2011, of Overland Pass Pipeline, which is an interstate natural gas liquids pipeline regulated by the FERC pursuant to the Interstate Commerce Act. Overland Pass provides transportation service pursuant to tariffs filed with the FERC.

Exploration & Production

Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation and payment of royalties, and the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves.

Our gas marketing business is subject to a variety of laws and regulations at the local, state and federal levels, including the FERC and the Commodity Futures Trading Commission regulations. In addition, natural gas markets continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations.

Other

Our Canadian assets are regulated by the Energy Resources Conservation Board (ERCB) and Alberta Environment. 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 ERCB and Alberta Environment have implemented an enforcement process with escalating consequences.

See Note 16 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our operations are subject to federal environmental laws and regulations as well as the state 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:

- From a well or drilling equipment at a drill site;
- Leakage from gathering systems, pipelines, processing or treating facilities, transportation facilities and storage tanks;
- Damage to oil and gas wells resulting from accidents during normal operations;
- Blowouts, cratering and explosions.

Because the requirements imposed by environmental laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, we may be liable for environmental damage caused by former operators of our properties.

We believe compliance with environmental laws and regulations will not have a material adverse effect on capital expenditures, earnings or 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 a discussion of specific environmental issues, see Environmental under Management s Discussion and Analysis of Financial Condition and Results of Operations and Environmental Matters in Note 16 of our Notes to Consolidated Financial Statements.

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COMPETITION

Williams Partners

For our gas pipeline business, the natural gas industry has undergone significant change over the past two decades. 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.

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, but the changes implemented at the state level have not required renegotiation of LDC contracts. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

States are in the process of developing new energy plans that may require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This could lower the growth of gas demand.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity. Future utilization of pipeline capacity will also depend on competition from LNG imported into markets and new pipelines from the Rockies and other new producing areas.

In our midstream business, we face regional competition with varying competitive factors in each basin. 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. Numerous factors impact any given customer s choice of a gathering or processing services provider, including rate, location, term, reliability, timeliness of services to be provided, pressure obligations and contract structure. We also compete in recruiting and retaining skilled employees. By virtue of the master limited partnership structure, WPZ provides us with an alternative source of capital, which helps us compete against other master limited partnerships for capital projects.

Exploration & Production

Our exploration and production business competes with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

In our gas marketing services business, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities, and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

Other

Ethylene and propylene markets, and therefore our olefins business, compete in a worldwide marketplace. Due to our NGL feedstock position at Geismar, we will benefit from the lower cost position 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 depending on their market balances. Generally, we are viewed primarily as a supplier to these companies and not as a direct competitor. 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 treater/processor of oil sands upgrader off-gas. Our extraction of liquids from the upgrader off-gas 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.

EMPLOYEES

At February 1, 2011, we had approximately 5,022 full-time employees. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 18 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 18 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

Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements relate to anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters. 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, obj potential, projects, scheduled, will or other similar expressions. These forward-looking statements are based on management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Financial condition and liquidity;

Business strategy;

Estimates of proved gas and oil reserves;

Reserve potential;

Development drilling potential;

Cash flow from operations or results of operations;

Seasonality of certain business segments;

Natural gas, natural gas liquids and crude oil prices and demand.

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:

Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices, and the availability and cost of capital;

Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);

The strength and financial resources of our competitors;

Development of alternative energy sources;

The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations (including climate change legislation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation, and rate proceedings;

Our 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;

Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;

Risks associated with future weather conditions;

Acts of terrorism;

Additional risks described in our filings with the Securities and Exchange Commission.

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

Risks Related to Separation Plan

If our plan to separate our exploration and production business is delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On February 16, 2011, we announced that our Board of Directors approved pursuing a plan to divide our businesses into two separate, publicly traded corporations. The plan calls for a separation of our exploration and production business through an initial public offering of up to 20 percent of the corporation holding that business in 2011 and a tax-free spinoff of our remaining interest in that corporation to our shareholders in 2012. The completion and timing of each of the transactions is dependent on a number of factors including, but not limited to, the macroeconomic environment, credit markets, equity markets, energy prices, the receipt of a tax opinion from counsel and/or Internal Revenue Service rulings, final approvals from our Board of Directors and other customary matters. We may not complete the transactions at all or complete the transactions on the timeline or on the terms that we announced. If the transactions are not completed or delayed, our stock price may decline and our growth potential may not be enhanced.

Risks Inherent in our Business

The long-term financial condition of our gas pipeline and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access, demand for those supplies in our traditional markets, and the prices of and market demand for natural gas.

The development of the additional natural gas reserves that are essential for our gas pipeline and midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, including environmental regulations, or the lack of available capital for these projects could adversely affect the development and production of additional reserves, as well as gathering, storage, pipeline transportation and import and export of natural gas supplies, adversely impacting our ability to fill the capacities of our gathering, transportation and processing facilities.

Production from existing wells and natural gas supply basins with access to our pipeline systems will also naturally decline over time. The amount of natural gas reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Additionally, the competition for natural gas supplies to serve other markets could reduce the amount of natural gas supply for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas transported on or gathered through our pipeline systems and cash flows associated with the gathering and transportation of natural gas, our customers must compete with others to obtain adequate supplies of natural gas. In addition, if natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted on a short-term basis, as well as with respect to our long-term recontracting activities. If new supplies of natural gas are not obtained to replace the natural decline in volumes from existing supply areas, if natural gas supplies are diverted to serve other markets, if development in new supply basins where we do not have significant gathering or pipeline systems reduces demand for our services, or if environmental regulators restrict new natural gas drilling, the overall volume of natural gas transported, gathered and stored on our system would decline, which could have a material

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adverse effect on our business, financial condition and results of operations. In addition, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

Significant prolonged changes in natural gas prices could affect supply and demand and cause a termination of our transportation and storage contracts or a reduction in throughput on the gas pipeline systems.

Higher natural gas prices over the long term could result in a decline in the demand for natural gas and, therefore, in long-term transportation and storage contracts or throughput on our gas pipeline systems. Also, lower natural gas prices over the long term could result in a decline in the production of natural gas resulting in reduced contracts or throughput on the gas pipeline systems. As a result, significant prolonged changes in natural gas prices could have a material adverse effect on our gas pipeline business, financial condition, results of operations and cash flows.

Prices for NGLs, natural gas and other commodities, including oil, are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses.

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices of NGLs, natural gas, oil, or other commodities, and the differences between prices of these commodities. Price volatility can 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. Any of the foregoing can also have an adverse effect on our business, results of operations, financial condition and cash flows.

The markets for NGLs, natural gas and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, NGLs, oil, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- The price and availability of other types of fuels;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and level of foreign imports;
- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas and oil markets;

The overall economic environment;

The credit of participants in the markets where products are bought and sold;

The adoption of regulations or legislation relating to climate change.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts may consist of wholesale contracts to buy and sell commodities, including contracts for natural gas, NGLs, oil and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty s obligation is inadequate, we will suffer a loss. Downturns in the economy or disruptions in the global credit markets could cause more of our counterparties to fail to perform than we expect.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and debt and equity issuances. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of natural gas and oil, and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, issue debt or equity securities or access other methods of financing on an economic basis to meet our capital expenditure budget. As a result, our capital expenditure plans may have to be adjusted.

Failure to replace reserves may negatively affect our business.

The growth of our Exploration & Production business depends upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis. If natural gas or oil prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

Our past success rate for drilling projects should not be considered a predictor of future commercial success. We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, skilled labor, capital or transportation;

Unexpected drilling conditions or problems;

Regulations and regulatory approvals;

Changes or anticipated changes in energy prices;

Compliance with environmental and other governmental requirements.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, oil and gas prices or assumptions as to future natural gas prices may lead to decreased earnings, losses, or impairment of oil and gas assets.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are proved reserves are those estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions, but should not be considered as a guarantee of results for future drilling projects.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings.

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 they 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.

We may not be able to maintain or replace expiring natural gas transportation and storage contracts at favorable rates or on a long-term basis.

Our primary exposure to market risk for our gas pipelines occurs at the time the terms of their existing transportation and storage contracts expire and are subject to termination. Upon expiration of the terms we may not be able to extend contracts with existing customers to obtain replacement contracts at favorable rates or on a long-term basis.

The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

The level of existing and new competition to deliver natural gas to our markets;

The growth in demand for natural gas in our markets;

Whether the market will continue to support long-term firm contracts;

Whether our business strategy continues to be successful;

The level of competition for natural gas supplies in the production basins serving us;

The effects of state regulation on customer contracting practices.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Although we have systems in place that use various methodologies to quantify commodity price risk associated with our businesses, these systems might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified.

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.

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under generally accepted accounting principles (GAAP) to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for NGLs and natural gas on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for NGLs or natural gas were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

Volumes are less than expected;

The hedging instrument is not perfectly effective in mitigating the risk being hedged;

The counterparties to our hedging arrangements fail to honor their financial commitments.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted. The Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The final impact of the Act on our hedging activities is uncertain at this time due to the requirement that the SEC and the Commodities Futures Trading Commission (CFTC) promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. These new rules and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts or reduce the availability of derivatives. Although we believe the derivative contracts that we enter into should not be impacted by position limits and should be exempt from the requirement to clear transactions through a central exchange or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers or the loss of any contracted volumes could result in a decline in our business.

Our gas pipeline and midstream businesses rely on a limited number of customers for a significant portion of their revenues. Although some of these customers are subject to long-term contracts, extensions or replacements of these contracts may not be renegotiated on favorable terms, if at all. The loss of all, or even a portion of the revenues from natural gas, NGLs or contracted volumes, as applicable, supplied by these customers, as a result of competition, creditworthiness, inability to negotiate extensions or replacements of contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations, and cash flows, unless we are able to acquire comparable volumes from other sources.

We are exposed to the credit risk of our customers, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers 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 may not be adequate to fully eliminate customer credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. 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.

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. Other companies with which we compete 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. 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 investments or acquisitions. 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. We may not be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

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Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.

There are operational risks associated with drilling for, production, gathering, transporting, storage, processing and treating of natural gas and the fractionation and storage of NGLs, including:

- Hurricanes, tornadoes, floods, fires, extreme weather conditions, and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages;
- Uncontrolled releases of natural gas (including sour gas), NGLs, brine or industrial chemicals;
- Collapse of storage caverns;
- Operator error;
- Damage inadvertently caused by third-party activity, such as operation of construction equipment;
- Pollution and environmental risks;
- Fires, explosions, craterings and blowouts;
- Risks related to truck and rail loading and unloading;
- Risks related to operating in a marine environment;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. 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. In spite of our precautions, an event such as those described above could cause considerable harm to people or property, and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

Our costs of maintaining or repairing our facilities may exceed our expectations and the FERC or competition in our markets may not allow us to recover such costs in the rates we charge for our services.

We could experience unexpected leaks or ruptures on our gas pipeline and midstream systems, or be required by regulatory authorities to undertake modifications to our systems that could result in a material adverse impact on our business, financial condition and results of operations if the costs of maintaining or repairing our facilities exceed current expectations and the FERC or competition in our markets do not allow us to recover such costs in the rates we charge for our service.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

We are not fully insured against all risks inherent to our business, including environmental accidents. We do not maintain insurance in the type and amount to cover all possible risks of loss.

We currently maintain excess liability insurance with limits of $610 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.

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Although we maintain property insurance on property 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 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. Only certain offshore key-assets are covered for property damage and the resulting business interruption when loss is due to a named windstorm event and coverage for loss caused by a named windstorm is significantly sub-limited. All of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured it could adversely affect our operations and financial condition.

In addition, any insurance company that provides coverage to us may experience negative developments that could impair their ability to pay any of our claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

The occurrence of any risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows, and our ability to repay our debt.

Execution of our capital projects subjects us to construction risks, increases in labor costs and materials, and other risks that may adversely affect financial results.

The growth in our gas pipeline and midstream businesses may be dependent upon the construction of new natural gas gathering, transportation, processing or treating pipelines and facilities or natural gas liquids fractionation or storage facilities, as well as the expansion of existing facilities. Construction or expansion of these facilities is subject to various regulatory, development and operational risks, including:

- The ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms;
- The availability of skilled labor, equipment, and materials to complete expansion projects;
- Potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project;
- Impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;
- The ability to construct projects within estimated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control, that may be material;
- The ability to access capital markets to fund construction projects.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve expected investment return, which could adversely affect our results of operations, financial position or cash flows.

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 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.

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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 fiduciary obligations with respect to WPZ as the general partner and to the limited partners of WPZ. Activities determined to involve fiduciary 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 interests is found to exist. Our control of the general partner of WPZ may increase the possibility of claims of breach of fiduciary 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.

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, and companies relationships with their independent public accounting firms. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact of that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board, the SEC or FERC could enact new accounting standards or FERC orders that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations, and financial condition.

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 and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments 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.

Our operating results for certain segments of our business might fluctuate on a seasonal and quarterly basis.

Revenues from certain segments 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. Additionally, changes in the price of natural gas could benefit one of our businesses, but disadvantage another. For example, our Exploration & Production business may benefit from higher natural gas prices, and our midstream business, which uses gas as a feedstock, may not.

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, and financial condition and cash flows.

Risks Related to Strategy and Financing