WPX Energy, Inc. | 2012 Annual Report

WPXENERGY.

WPX Energy specializes in producing natural gas, natural gas liquids and oil from non-conventional resources such as tight-sands and shale formations. We have three decades of experience in our industry. WPX Energy, previously a wholly owned subsidiary of Williams, became a separate, independent company a year ago.

Forward-Looking Statements

Certain matters discussed in this report, except historical information, include forward-looking statements. Although WPX believes such statements are based on reasonable assumptions, no assurance can be given that every objective will be achieved. For more detail, see the disclosure beginning on page 29 of the Form 10-K in this report.

strength

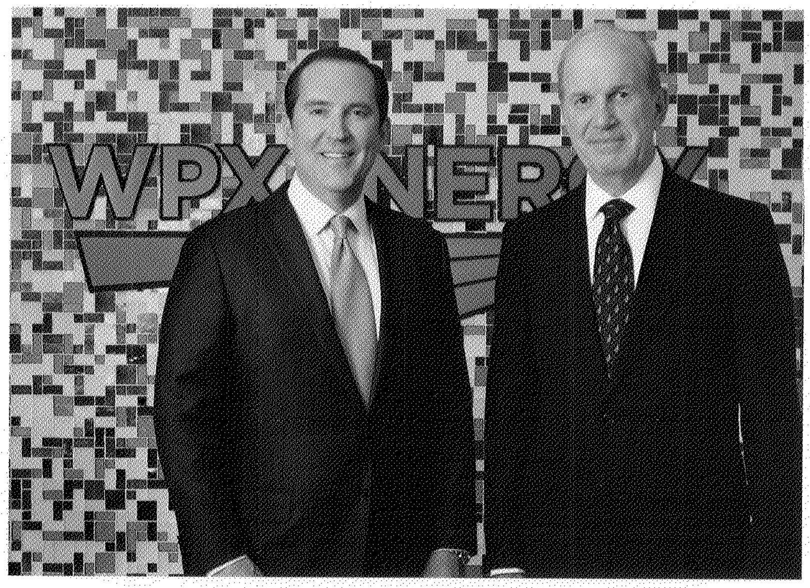
A single word that encapsulates

On the Cover

WPX completed 548 new wells on a gross basis in 2012, including 41 wells in the oil-rich Bakken Shale where the company has initiated multi-well development pads. During 2012, WPX increased its Bakken Shale oil production by 98 percent.

4.5 approximately trillion cubic feet

in proved domestic reserves



From left to right:

Ralph A. Hill
President and Chief Executive Officer

William G. Lowrie
Chairman of the Board of Directors

everything about WPX Energy.

Dear Fellow Stockholders: In 2012, WPX Energy emerged as an independent company. Immediately, WPX was confronted with one of the most difficult commodity price environments that the industry has seen in more than a decade.

Natural gas prices decreased more than 30 percent for the year and dropped below $2 per Mcf in April. The average realized price for WPX's natural gas production decreased 22 percent for the year. Weak prices were driven by a combination of factors, primarily abundant supply and one of the warmest winters on record.

The corresponding impact on revenues, cash flow and development plans easily could have crippled a new publicly traded company like WPX – albeit one with 30 years of industry experience and know-how. However, it did not. Together, the company's management team and 1,200 employees met these headwinds with drive, discipline, determination and flexibility – demonstrating the strength of WPX's balance sheet and diversified portfolio. We adjusted our plans, moved to reduce spending on natural gas drilling and shifted more resources and dollars toward increasing oil production, most notably in the Bakken Shale play in the Williston Basin, where WPX has 84,000 acres.

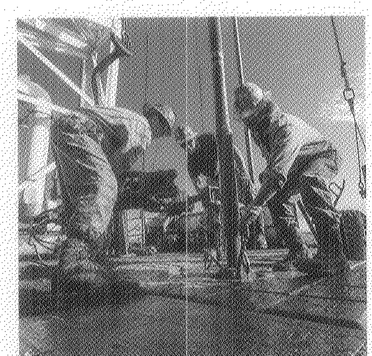
Reducing rig counts in the Piceance Basin and Marcellus Shale play in the Appalachian Basin is a difficult decision to make when one considers the extent of proved, probable and possible (3P) reserves that WPX has in these areas. In the Piceance, WPX has 12 trillion cubic feet of natural gas reserves, including associated condensate and natural gas liquids. In the Marcellus, WPX has 2 trillion cubic feet of reserves using the same measure. These are two of the nation's best energy basins. Even so, pulling back was the right decision.

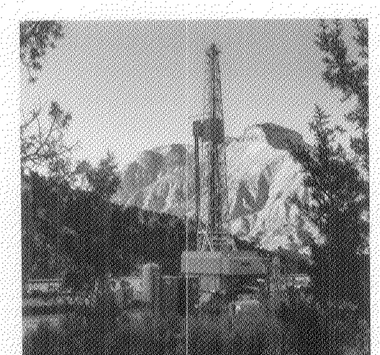
Consider the results. WPX achieved 98 percent growth in Bakken oil volumes. Overall oil production – including volumes from the company's other properties, both domestically and internationally – increased 40 percent. WPX added 634 billion cubic feet in domestic reserves as we proved up potential reserves through drilling. The company's total 3P reserves remained just above 18 trillion cubic feet, which was nearly the same as 2011 despite the impact of significantly lower 2012 commodity prices, which affects the amount of reserves companies can record. At this point, WPX's 3P reserves do not factor in the company's recent natural gas discovery in the Piceance Basin's Niobrara Shale. This discovery in the Niobrara and the attendant 180,000 acres already held by WPX's existing production have the potential to double the company's 3P reserves over the long term. Financially, WPX finished 2012 with $1.65 billion in liquidity. This measure is important because it helps highlight the company's ability to meet its obligations and execute its drilling plans.

For WPX – even in the face of the most challenging commodity price environments or circumstances – it's not about surviving. It's about thriving. The company will always be focused on doing what it takes to create, sustain and grow stockholder value. You should expect nothing less from WPX. As we look to 2013 and beyond, let's discuss what distinguishes this company. We believe it's our unyielding approach to efficiency and our passion to make WPX's operations safer and more profitable. Efficiency is what we're all about. WPX is dedicated to continuous improvement.

WPX's strength is efficient, large-scale energy

WPX's strength is efficient, large-scale energy development in world-class resource plays. This is an approach to operating that the company has carefully and consistently crafted and built in the Piceance Basin, where WPX derives both natural gas and value-adding natural gas liquids from the same production stream. In the early days of this play, it took 30 days to drill a well. A decade ago, it took 20. Now, WPX's drilling times are down to an average of 8 days in the Piceance Valley, with a record of just 3.7 days set in 2012.





Over the past decade, WPX introduced high-efficiency rigs that can currently drill up to 22 wells from the same pad, saving time and money while drastically reducing land usage by as much as 75 percent and preserving precious resources through recycling nearly 100 percent of our water. WPX also pioneered simultaneous operations onshore – drilling and completing wells on the same pad as producing wells – and remote frac pads, where new wells that are being developed can be completed on multiple pads at the same time from more than 3 miles away. Using these innovations, today WPX operates 4,100 wells in the Piceance on 216,000 acres. We are the largest producer of natural gas in Colorado and have costs that average 20-30 percent less than our competitors, due in part to our large-scale position. WPX's remaining inventory in this area includes approximately 10,000 undrilled locations on a 3P basis.

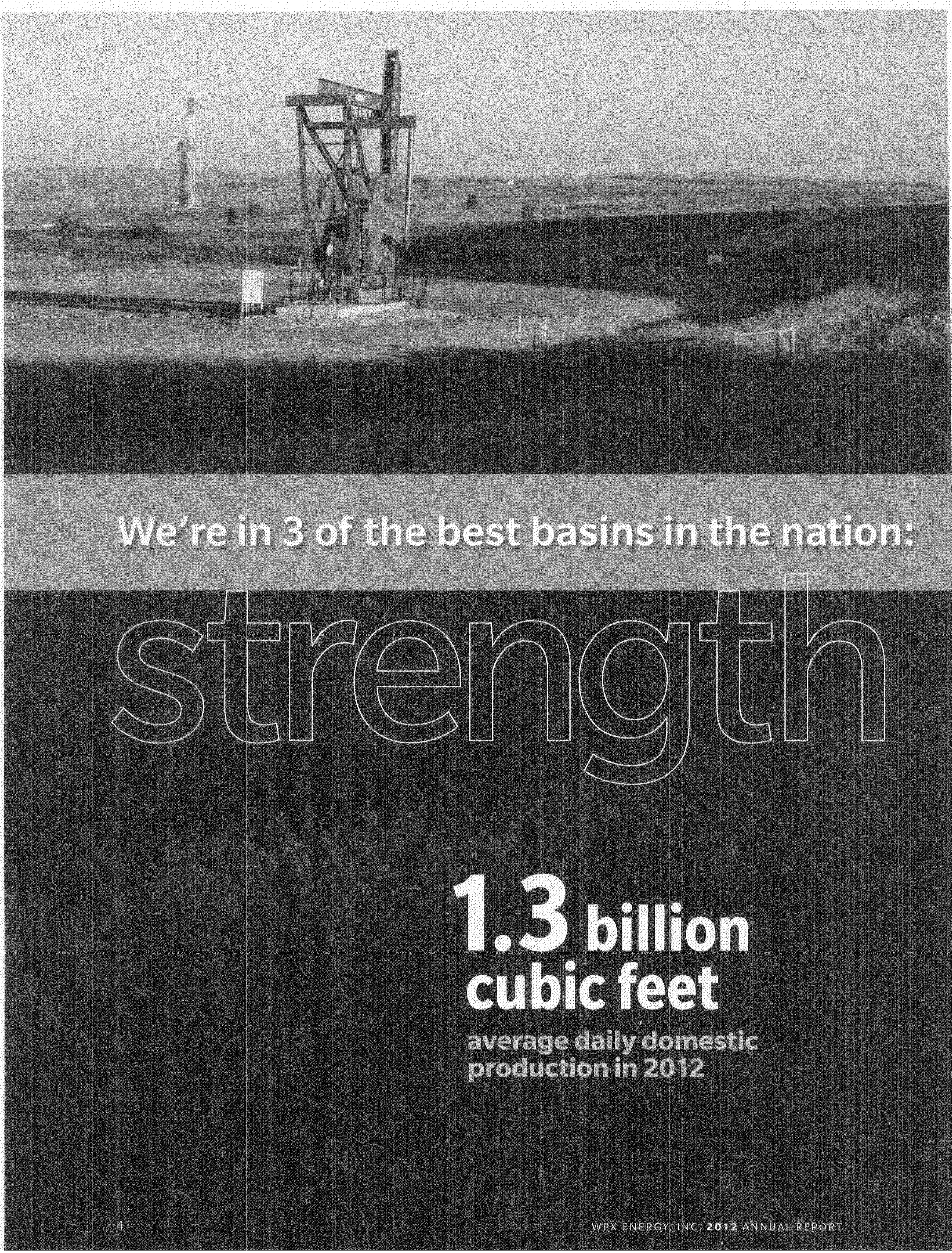
Now, WPX is applying the same innovative, efficiency-driven, rate-of-return approach in our newer areas such as the Bakken Shale oil development in the Williston Basin and one of the nation's best pure-play natural gas areas – the Marcellus Shale in the Appalachian Basin. WPX's recent drilling costs on long-lateral horizontal wells in the Bakken have improved 10-20 percent through multi-well development pads and new completion practices. This improvement in well costs places WPX competitive with the industry average on the Fort Berthold Indian Reservation, where WPX's costs include a pricier proppant – ceramics instead of just sand – to keep the fractures open longer. We believe the added cost of this completion technique will lead to individual wells that deliver higher ultimate recovery rates. In the Marcellus, WPX reduced completion costs by 46 percent from late 2011 to late 2012 and improved the amount of time from when a well is first drilled to when the rig is released by 60 percent since late 2010 – all while growing proved reserves in Pennsylvania by 1,000 percent.

We're building on the efficiency gains and cost reductions in WPX's three primary basins by consolidating the company's drilling organization into one team. Previously, there were separate drilling functions in each of WPX's basins. The move is designed to further reduce costs and cycle times, optimize the deployment of drilling personnel, consolidate contractor and vendor services for best pricing and add more flexibility to ramp up or ramp down activity levels at any given time. At WPX,

strength

development in world-class resource plays.

634 billion cubic feet in 2012
domestic reserves additions



We're in 3 of the best basins in the nation:

strength

1.3 billion cubic feet

average daily domestic production in 2012 our ongoing goal is to accomplish the company's drilling plans using fewer rigs in fewer days. Improving costs is critical in any business environment, and even more so in today's commodity price environment.

For 2013, approximately 75-80 percent of WPX's $1 billion-$1.2 billion capital budget is devoted to developing more oil in the Bakken Shale and more liquids-rich production in the Piceance, along with new oil exploration. WPX expects to grow Bakken oil production by 25-30 percent this year and spend an estimated $95 million to drill eight exploratory oil wells and acquire leasehold in new areas. This represents a more active approach to exploration than during our time as a wholly owned subsidiary of Williams. As a pure-play E&P company, WPX will now test plays earlier in their development and seek to acquire acreage through grassroots leasing at a lower cost of entry.

We are optimistic about oil exploration and hopeful for economically viable discoveries like the major natural gas find we announced this year in the Piceance Basin's Niobrara Shale. Obviously, there is risk as well, which is why the majority of WPX's capital is still geared toward existing producing properties where there is less risk in generating value and attractive returns. With regard to natural gas, WPX will remain disciplined and reduce drilling. This will impact the company's total anticipated production in 2013 by an estimated 4-7 percent decline. However, the benefit of having diversified assets both geographically and by product gives WPX the ability to shift capital toward higher-returning portions of the company's portfolio.

Operationally, WPX has a relentless drive to do things the right way – which is recognized by important agencies with whom we interact to secure permits and approvals for the company's drilling plans. WPX earned six prestigious awards last year in Colorado, New Mexico and North Dakota, including honors from the U.S. Forest Service, the Three Affiliated Tribes and the Colorado Oil and Gas Conservation Commission. The desire to be an excellent operator is ingrained in the company's culture and its commitment to safety. You can also see evidence of this fact in WPX's recordable injury rate. In 2012, the rate was reduced by 50 percent vs. 2011. Wyoming employees also completed nine years without a lost-time accident. These results are a picture of the quality, character and commitment of the entire WPX family. We're tremendously proud of what our employees accomplished to keep WPX running safely, smoothly and seamlessly in the midst of a major corporate transition following our spinoff from Williams.

WPX's story is one of strength: 4.65 trillion cubic feet equivalent in proved reserves; 16,600 remaining domestic undrilled 3P locations; 200 years of combined experience on our senior management team; $1.65 billion in liquidity; and a 100 percent drilling success rate in 2012. WPX's 2013 business objectives are fourfold: (1) grow oil production (2) maintain disciplined natural gas development (3) continually improve costs, and (4) pursue new opportunities, including oil exploration and our Niobrara Shale discovery where our 2013 plan includes four more horizontal wells to prove up adjacent acreage and test the repeatability of the play. As a company, we invite you to join us long term. Thank you for your support and interest.

William G. Lowrie

William G. Lowrie
Chairman of the Board

Ralph A. Hill

Ralph A. Hill
President and Chief Executive Officer

April 5, 2013

the Piceance, the Bakken and the Marcellus.

2012 Achievements

- Niobrara Shale discovery well was completed in December; produced an initial high of 16 MMcf/d
- Completed $306 million sale of non-strategic properties in Texas and Oklahoma
- Achieved adjusted EBITDAX of $1 billion
- Increased total production 4% to 1,386 MMcfe/d
- Total NGL and oil production increased 14% to 47,000 bbl/d
- 148% reserves replacement rate for domestic oil and NGL production
- Doubled Bakken Shale oil production. Finished year at 11,600 bbl/d
- 100% drilling success rate over 548 gross wells
- Completed year with $1.65 billion liquidity
- Marcellus natural gas volumes increased 320%: 4th quarter average was 71 MMcf/d
- Completed 240 gross wells in the Piceance

Directors

Kimberly S. Bowers
Independent Director
Executive Vice President and President Retail
Valero Energy Corporation

John A. Carrig
Independent Director
Former President & COO
ConocoPhillips

William R. Granberry
Independent Director
Member
Compass Operating Co., LLC

Don J. Gunther
Independent Director
Former Vice Chairman
Bechtel Group

Robert K. Herdman
Independent Director
Managing Director
Kalorama Partners LLC

Ralph A. Hill
Inside Director
President and CEO
WPX Energy, Inc.

Kelt Kindick
Independent Director
Sr. Advisor & Former CFO
Bain & Company, Inc.

Henry E. Lentz
Independent Director
Former Managing Director
Lazard Fréres & Co.

George A. Lorch
Independent Director
Chairman Emeritus
Armstrong Holdings, Inc.

William G. Lowrie, Chairman
Independent Director
Former Deputy CEO
BP Amoco PLC

David F. Work
Independent Director
Former Executive
BP Amoco Corp.

Senior Leadership

Ralph A. Hill
President and Chief Executive Officer

Bryan K. Guderian
Sr. Vice President
Operations

Steven G. Natali
Sr. Vice President
Exploration

Neal A. Buck
Sr. Vice President
Business Development and Land

Rodney J. Sailor
Sr. Vice President and Chief Financial Officer

Marcia M. MacLeod
Sr. Vice President
Human Resources and Administration

James J. Bender
Sr. Vice President and General Counsel

Michael R. Fiser
Sr. Vice President
Marketing

Committees

Audit
John Carrig
Robert Herdman, Chair
Kelt Kindick
William Lowrie

Compensation
William Granberry, Chair
Henry Lentz
David Work

Corporate Governance and Nominating
Kimberly Bowers
Don Gunther
George Lorch, Chair

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

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

Commission file number 1-35322

SEC MAIL PROCESSING
RECEIVED
APR - 5 2013
WASH, D.C. 193 SECTION

WPX Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State or Other Jurisdiction of Incorporation or Organization)**	**45-1836028** **(IRS Employer Identification No.)**
One Williams Center, Tulsa, Oklahoma **(Address of Principal Executive Offices)**	**74172-0172** **(Zip Code)**

855-979-2012
(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, $0.01 par value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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 $3,204,886,378.

The number of shares outstanding of the registrant's common stock outstanding at February 26, 2013 was 200,132,338.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be delivered to stockholders in connection with its 2013 Annual Meeting of Stockholders are incorporated by reference into Part III.

WPX ENERGY, INC.

FORM 10-K

TABLE OF CONTENTS

CERTAIN DEFINITIONS

The following oil and gas measurements and industry and other terms are used in this Form 10-K. As used herein, production volumes represent sales volumes, unless otherwise indicated.

Bakken Shale—means the Bakken Shale oil play in the Williston Basin and can include the Upper Three Forks formation.

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

BBtu—means one billion BTUs.

BBtu/d—means one billion BTUs per day.

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

Bcf/d—means one billion cubic feet per day.

Boe—means barrels of oil equivalent.

Boe/d—means barrels of oil equivalent 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.

FERC—means the 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.

LOE—means lease and other operating expense excluding production taxes, ad valorem taxes and gathering, processing and transportation fees.

Mbbls—means one thousand barrels.

Mbbls/d—means one thousand barrels per day.

Mboe/d—means one thousand barrels of oil equivalent per day.

Mcf—means one thousand cubic feet.

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

MMbbls—means one million barrels.

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, condensate or NGLs to six thousand cubic feet of natural gas.

MMcfe/d—means one million cubic feet of gas equivalent per day using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

NGLs—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.

PART I

In this report, WPX (which includes WPX Energy, 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 WPX as the "Company" or "WPX Energy."

Throughout this report we "incorporate by reference" certain information in parts of other documents filed with the Securities and Exchange Commission (the "SEC"). The SEC allows us to disclose important information by referring to it in that manner. Please refer to such documents for information.

We are making forward-looking statements in this report. In "Item 1A: Risk Factors" we discuss some of the risk factors that could cause actual results to differ materially from those stated in the forward-looking statements.

Item 1. *Business*

SEPARATION FROM THE WILLIAMS COMPANIES, INC.

On December 31, 2011 (the "Distribution Date"), WPX Energy, Inc. became an independent, publicly traded company as a result of a distribution by The Williams Companies, Inc. ("Williams") of its shares of WPX to Williams' stockholders. On the Distribution Date, Williams' stockholders of record as of the close of business on December 14, 2011 (the "Record Date") received one share of WPX common stock for every three shares of Williams' common stock held as of the Record Date (the "Distribution"). WPX is comprised of Williams' former natural gas and oil exploration and production business. Our common stock began trading "regular-way" under the ticker symbol "WPX" on the New York Stock Exchange on January 3, 2012.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 855-979-2012.

WPX ENERGY, INC.

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserves base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our positions in the Bakken Shale oil play in North Dakota and the Marcellus Shale natural gas play in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ("Apco"), which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol "APAGF." Our international interests make up approximately 3 percent of our total proved reserves. In consideration of this percentage, unless specifically referenced herein, the information included in this section relates only to our domestic activity.

We have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. Our proved reserves at December 31, 2012 were 4,650 Bcfe, comprised of 4,491 Bcfe in domestic reserves and 159 Bcfe in net international reserves. Our domestic reserves reflect a mix of 75.0 percent natural gas, 14.8 percent NGLs and 10.2 percent crude oil. During 2012, we replaced our domestic production for all commodities at a rate of 28 percent. For oil and NGL alone, we replaced 148 percent of our oil and NGL production. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

We report financial results for two segments, our domestic segment and our international segment. Our international segment primarily consists of Apco. Except as otherwise specifically noted, either by a reference to Apco or to other international operations, the following description of our business is focused on our domestic segment, which is our dominant segment and which is central to an understanding of our business taken as a whole.

BUSINESS OVERVIEW

Our Business Strategy

Our business strategy is to increase shareholder value by finding and developing reserves and producing natural gas, oil and NGLs at costs that generate an attractive rate of return on our investment.

- *Efficiently Allocate Capital for Optimal Portfolio Returns.* We expect to allocate capital to the most profitable opportunities in our portfolio based on commodity price cycles and other market conditions, enabling us to continue to grow our reserves and production in a manner that maximizes our return on investment. In determining which drilling opportunities to pursue, we target a minimum after-tax internal rate of return on each operated well we drill of 15 percent. While we have a significant portfolio of drilling opportunities that we believe meet or exceed our return targets even in challenging commodity price environments, we are disciplined in our approach to capital spending and will adjust our drilling capital expenditures based on our level of expected cash flows, access to capital and overall liquidity position.

- *Continue Our Cost-Efficient Development Approach.* We focus on developing properties where we can apply development practices that result in cost-efficiencies. We manage costs by focusing on establishing large scale, contiguous acreage blocks where we can operate a majority of the properties. We believe this strategy allows us to better achieve economies of scale and apply continuous technological improvements in our operations. We have replicated these cost-efficient approaches in the Marcellus Shale and intend to do so in the Bakken Shale.

- *Target a More Balanced Commodity Mix in Our Production Profile through development and exploration.* With our Bakken Shale and our liquids-rich Piceance Basin assets, we have a significant drilling inventory of oil- and liquids-rich opportunities that we intend to develop in order to achieve a more balanced commodity mix in our production. We refer to the Piceance Basin as "liquids-rich" because our proved reserves in that basin consist of "wet," as opposed to "dry," gas and have a significant liquids component. We will continue to pursue other oil- and liquids-rich organic development and acquisition opportunities that meet our investment returns and strategic criteria.

- *Maintain Substantial Financial Liquidity and Manage Commodity Price Sensitivity.* We plan to maintain substantial liquidity through a mix of cash on hand and availability under our credit facility. In addition, we have engaged and will continue to engage in commodity derivative hedging activities to maintain a degree of cash flow stability. Typically, we target hedging approximately 50 percent of expected revenue from domestic production during a current calendar year in order to strike an appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. As of February 25, 2013, our estimated domestic natural gas production revenues were approximately 50 percent hedged for 2013 and our estimated domestic oil production revenues were 59 percent hedged for 2013.

- *Pursue Strategic Acquisitions with Significant Resource Potential through exploration activities.* We have a history of acquiring undeveloped properties that meet our disciplined return requirements and other acquisition criteria to expand upon our existing positions as well as acquiring undeveloped acreage in new geographic areas that offer significant resource potential. We expect to opportunistically acquire acreage positions in new areas where we feel we can establish significant scale and replicate our cost-efficient development approach.

SIGNIFICANT PROPERTIES

Our principal areas of operation are the Piceance Basin, Bakken Shale/Williston Basin, Marcellus Shale/ Appalachian Basin, Powder River Basin, San Juan Basin and, through our ownership of Apco, Colombia and Argentina.

Piceance Basin

We entered the Piceance Basin in May 2001 with the acquisition of Barrett Resources and since that time have grown to become the largest natural gas producer in Colorado. Our Piceance Basin properties currently comprise our largest area of concentrated development drilling.

During 2012, we operated an average of 5.4 drilling rigs in the basin, including 4.4 in the Piceance Valley and one in the Piceance Highlands. We expect to operate five rigs in the Piceance Basin in 2013. We had an average of 673 MMcf/d of net gas production from our Piceance Basin properties along with an average of 27.5 Mbbls/d of NGLs and 2.3 Mbbls/d of condensate recovered from our Piceance Basin properties. Capital expenditures were approximately $327 million which included the completion of 240 gross (209 net) wells in 2012. As of December 31, 2012, another 15 gross wells were awaiting completions. A large majority of our natural gas production in this basin currently is gathered through a system owned by Williams Partners L.P. ("Williams Partners") and delivered to markets through a number of interstate pipelines.

The Piceance Basin is located in northwestern Colorado. Our operations in the basin are divided into two areas: the Piceance Valley and the Piceance Highlands. Our Piceance Valley area includes operations along the Colorado River valley and is the more developed area where we have produced consistent, repeatable results. The Piceance Highlands, which are those areas at higher elevations above the river valley, contain vast development opportunities that position us well for growth in the future as infrastructure expands and efficiency improvements continue. Our development activities in the basin are primarily focused on the Williams Fork section within the Mesaverde formation. The Williams Fork can be over 2,000 feet in thickness and is comprised of several tight, interbedded, lenticular sandstone lenses encountered at depths ranging from 6,000 to 9,000 feet. In order to maximize producing rates and recovery of natural gas reserves we must hydraulically fracture the well using a fluid system comprised of 99 percent water and sand. Advancements in completion technology, including the use of microseismic data have enabled us to more effectively stimulate the reservoir and recover a greater percentage of the natural gas in place.

We recently announced a successful discovery in the Niobrara formation which has the potential to significantly increase our natural gas reserves and daily production in future years. The discovery well produced an initial high of 16 million cubic feet per day at a flowing pressure of 7,300 pounds per square inch. The Niobrara and Mancos Shales are generally located at depths of 10,000 to 13,000 feet. We have the lease rights to approximately 180,000 net acres of the Niobrara/Mancos Shale play that underlies our expansive leasehold position in the Piceance Basin. Substantial gathering and processing infrastructure is in place to accommodate additional gas volumes from the area, as is take-away capacity from the basin. Gas produced from the Niobrara and Mancos Shales can be processed without modification to existing gas treatment facilities.

Bakken Shale/Williston Basin

In December 2010, we acquired leasehold positions of approximately 85,800 net acres in the Williston Basin. All of these properties are on the Fort Berthold Indian Reservation in North Dakota and we are the primary operator. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results as well as the publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken and Three Forks formation, the primary targets for all of the well locations in our current drilling inventory.

During 2012, we operated an average of 5.7 rigs on our Bakken properties and we had an average of 10.3 Mboe/d of net production from our Bakken Shale wells. Capital expenditures were approximately $521 million which included the completion of 41gross (27 net) wells in 2012. As of December 31, 2012, another 5 gross wells were awaiting completion.

We are developing oil reserves through horizontal drilling in the Middle Bakken and plan to develop the Upper Three Forks Shale oil formations utilizing drilling and completion expertise gained in part through experience in our other basins. Based on our subsurface geological analysis, we believe that our position lies in the area of the basin's greatest potential recovery for Bakken formation oil. Currently our Bakken Shale development has the highest incremental returns of any of our drilling programs.

Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada, covering approximately 202,000 square miles, of which 143,000 square miles are in the United States. The basin produces oil and natural gas from numerous producing horizons including the Bakken, Three Forks, Madison and Red River formations. A report issued by the U.S. Geological Survey in April 2008 classified the Bakken formation as the largest continuous oil accumulation ever assessed by it in the contiguous United States.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members referred to as the Upper, Middle and Lower Bakken Shales. The formation ranges up to 150 feet thick and is a continuous and structurally simple reservoir. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The Middle Bakken, which varies in composition from a silty dolomite to shaly limestone or sand, serves as the productive formation and is a critical reservoir for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation has recently been exploited utilizing the same horizontal drilling and advanced completion techniques as the Bakken development. Drilling in the Three Forks formation began in mid-2008 and a number of operators are currently drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation and the evolution of completion techniques, we believe that most of our Williston Basin acreage is prospective in the Three Forks formation.

Our acreage in the Bakken Shale, as well as a portion of our acreage in the Piceance Basin and Powder River Basin, is leased to us by or with the approval of the federal government or its agencies, and is subject to federal authority, the National Environmental Policy Act ("NEPA"), the Bureau of Indian Affairs or other regulatory regimes that require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands. These regulatory regimes impose obligations on the federal government and governmental agencies that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals and could result in certain instances in the cancellation of existing leases.

Marcellus Shale/Appalachian Basin

Our Marcellus Shale acreage is located in four principal areas of the play within Pennsylvania: the northeast portion of the play in and near Susquehanna County; the southwest in and around Westmoreland County; centrally in Clearfield and Centre Counties and the east in Columbia County. We have expanded our position since our entry into the Marcellus Shale in 2009, both organically and through third-party acquisitions. We are the primary operator on our acreage for all four areas and plan to develop our acreage using horizontal drilling and completion expertise in part gained through operations in our other basins. A third party gathering system providing the main trunkline out of the Susquehanna area was completed in December 2011 and compression is being added to the system to serve expected volume growth.

During 2012, we operated an average of 2.1 rigs on our Marcellus Shale properties and we had an average of 63 MMcfe/d of net production from our Marcellus Shale wells. Production levels were hampered for much of 2012 by high line pressures on the aforementioned third party gathering system. Capital expenditures were approximately $356 million which included the completion of 54 gross (33 net) wells in 2012 . As of December 31, 2012, another 25 gross wells were awaiting completion.

The Marcellus Shale formation is the most expansive shale gas play in the United States, spanning six states in the northeastern United States. The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet, covering approximately 95,000 square miles at an average net thickness of 50 feet to 300 feet.

Powder River Basin

We own a large position in coal bed methane reserves in the Powder River Basin and together with our co-developer, Lance Oil & Gas Company Inc., control 887,555 acres, of which our ownership represents 398,470 net acres. We share operations with our co-developer and both companies have extensive experience producing from coal formations in the Powder River Basin dating from its earliest commercial growth in the late 1990s. The natural gas produced is gathered by a system owned by our co-developer.

During 2012, we had an average of 209 MMcfe/d of net production from our Powder River Basin properties. Capital expenditures were approximately $7 million which included the completion of 150 gross (92 net) wells in 2012 . The majority of these wells were drilled in prior years and completed the dewatering process in 2012. In 2013, we expect a level of expenditures similar to our 2012 expenditures. Our Powder River Basin properties are located in northeastern Wyoming. Our development operations in this basin are focused on coal bed methane plays in the Big George and Wyodak project areas. Initially, coal bed methane wells typically produce water in a process called dewatering. This process lowers pressure, allowing the natural gas to flow to the wellbore. As the coal seam pressure declines, the wells begin producing methane gas at an increasing rate. As the wells mature, the production peaks, stabilizes and then begins declining. The average life of a coal bed methane well in the Powder River Basin ranges from 5 to 15 years. While these wells generally produce at much lower rates with fewer reserves attributed to them when compared to conventional natural gas wells in the Rocky Mountains, they also typically have higher drilling success rates and lower capital costs.

The coal seams that we target in the Powder River Basin have been extensively mapped as a result of a variety of natural resource development projects that have occurred in the region. Industry data from over 25,000 wellbores drilled through the Ft. Union coal formation allows us to determine critical data such as the aerial extent, thickness, gas saturation, formation pressure and relative permeability of the coal seams we target for development, which we believe significantly reduces our dry hole risk.

San Juan Basin

We acquired our San Juan Basin properties as part of Williams' acquisition of Northwest Energy in 1983. These properties represented the first major area of natural gas exploration and development activities for Williams. Our San Juan Basin properties include holdings across the basin producing primarily from the Mesa Verde, Fruitland Coal and Mancos Shale formations which are predominantly gas bearing. We operate two units in New Mexico (Rosa and Cox Canyon) as well as several non-unit properties, and we operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We also own properties operated by other operators in New Mexico and Colorado. Approximately 60 percent of our net San Juan Basin production comes from our operated properties.

During 2012, we had an average of 133 MMcfe/d of net production from our San Juan Basin properties. Capital expenditures were approximately $14 million which included the completion of 11 gross (6 net) wells.

According to a September 2010 Wood Mackenzie report, the San Juan Basin is one of the oldest and most prolific coal bed methane plays in the world. The Fruitland coal bed extends to depths of approximately 4,200 feet with net thickness ranging from zero to 100 feet. The Mesa Verde play is the top producing tight gas play in the basin with total thickness ranging from 500 to 2,500 feet. The Mesa Verde is underlain by the upper Mancos Shale and overlain by the Lewis Shale.

International

We hold an approximate 69 percent controlling equity interest in Apco. Apco in turn owns interests in several blocks in Argentina, including concessions in the Neuquén, Austral, Northwest and San Jorge Basins, and in three exploration permits in Colombia, with its primary properties consisting of the Neuquén and Austral Basin concessions. Apco's oil and gas reserves are approximately 58 percent oil, 38 percent natural gas and 4 percent liquefied petroleum gas.

During 2012, Apco had an average of 13.3 Mboe/d of net production.

Apco participated in the drilling of 37 gross wells operated by its partners in 2012. Apco spent, for its direct ownership interest, approximately $59 million in capital expenditures.

The government of Argentina has implemented price control mechanisms over the sale of natural gas and over gasoline prices in the country. As a result of these controls and other actions by the Argentine government, sales price realizations for natural gas and oil sold in Argentina are generally below international market levels and are significantly influenced by Argentine governmental actions.

We also hold additional international assets in northwest Argentina that are not part of Apco's holdings.

Other Properties

Our other holdings, amounting to less than one percent of our assets, are comprised of gas reserves in the Green River Basin of southwest Wyoming.

Acquisitions and Divestitures

In 2012, we disposed of our holdings in the Barnett Shale and the Arkoma Basin for $306 million. The Barnett Shale properties included approximately 27,000 net acres, interests in 320 wells and 91 miles of pipeline. The Arkoma properties included approximately 66,000 net acres, interests in 525 wells and 115 miles of pipeline.

Our acquisitions during 2012 consisted of miscellaneous leasehold purchases of $111 million with minimal associated production. The majority of these purchases were for oil exploration leaseholds. We may from time to time dispose of producing properties and undeveloped acreage positions if we believe they no longer fit into our strategic plan.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. In addition, leases on Native American reservations are subject to Bureau of Indian Affairs and other approvals unique to those locations. As is customary in the industry in the case of undeveloped properties, a limited investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which can result in litigation and delay or loss of our ability to realize the benefits of our leases.

Reserves and Production Information

We have significant oil and gas producing activities primarily in the Rocky Mountain, northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. Proved reserves and revenues related to international activities are approximately 3 percent and 4 percent, respectively, of our total international and domestic proved reserves and revenues from producing activities. Accordingly, unless specifically stated otherwise, the information in the remainder of this Item 1 relates only to the oil and gas activities in the United States.

Oil and Gas Reserves

The following table sets forth our estimated domestic net proved developed and undeveloped reserves expressed by product and on a gas equivalent basis for the reporting periods December 31, 2012, 2011 and 2010.

	As of December 31, 2012				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(a)	%
Proved Developed	2,170,681	64,910	23,740	2,702,579	60%
Proved Undeveloped	1,198,392	45,449	52,807	1,787,928	40%
Total Proved-Domestic	3,369,073	110,359	76,547	4,490,507	

	As of December 31, 2011				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(a)	%
Proved Developed	2,497,291	72,139	13,555	3,011,457	59%
Proved Undeveloped	1,485,644	61,938	33,568	2,058,676	41%
Total Proved-Domestic	3,982,935	134,077	47,123	5,070,133	

	As of December 31, 2010				
	Gas (MMcf)	NGL (Mbbls)	Oil (Mbbls)	Equivalent (MMcfe)(a)	%
Proved Developed	2,368,465	48,688	3,973	2,684,431	58%
Proved Undeveloped	1,545,739	47,169	20,302	1,950,567	42%
Total Proved-Domestic	3,914,204	95,857	24,275	4,634,998	

(a) Oil and NGLs converted to MMcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

The following table sets forth our estimated domestic net proved reserves for our largest areas of activity expressed by product and on a gas equivalent basis as of December 31, 2012 .

	As of December 31, 2012			
	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Equivalent (MMcfe)
Piceance Basin	2,338,554	103,094	8,755	3,009,650
Bakken Shale	34,074	6,790	67,463	479,593
Marcellus Shale	322,400	—	—	322,400
Powder River Basin	235,127	17	110	235,890
San Juan Basin	419,967	458	78	423,182
Other	18,951	—	141	19,792
Total Proved-Domestic	3,369,073	110,359	76,547	4,490,507

We prepare our own reserves estimates and approximately 99 percent of our reserves are audited by Netherland, Sewell & Associates, Inc. ("NSAI").

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

Our 2012 year-end estimated proved reserves were derived using an average natural gas price of $2.39 per Mcf, an average oil price of $82.32 per barrel and average NGL price of $37.01 per barrel. These prices were calculated from the 12-month average, first-of-the-month price for the applicable indices for each basin as adjusted for locational price differentials. During 2012 , we added 634 Bcfe of additions to our proved reserves. During 2012, we participated in the drilling of 548 gross wells at a net capital cost of approximately $1,130 million.

Proved reserves sensitivity by price scenario

The SEC disclosures rules allow for optional reserves sensitivity analysis, such as the sensitivity that oil and natural gas reserves have to price fluctuations. We have chosen to compare domestic proved reserves from the 2012 SEC case to an Alternate Price Scenario which applies prices from the 2011 SEC case to the 2012 SEC case.

The 2012 SEC case was derived using the pricing previously described. The Alternate Price Scenario reflects prices used for our year-end 2011 reserves which were calculated using the 12-month average, first-of-the-month price during 2011 for the applicable indices for each basin, as adjusted for local price differentials. Applying the prices used for our year-end 2011 reserves to the year-end 2012 reserves resulted in an average natural gas price of $3.68 per Mcf, an average oil price of $86.75 per barrel, and an average NGL price of $51.83 per barrel. This sensitivity scenario was not audited by a third party.

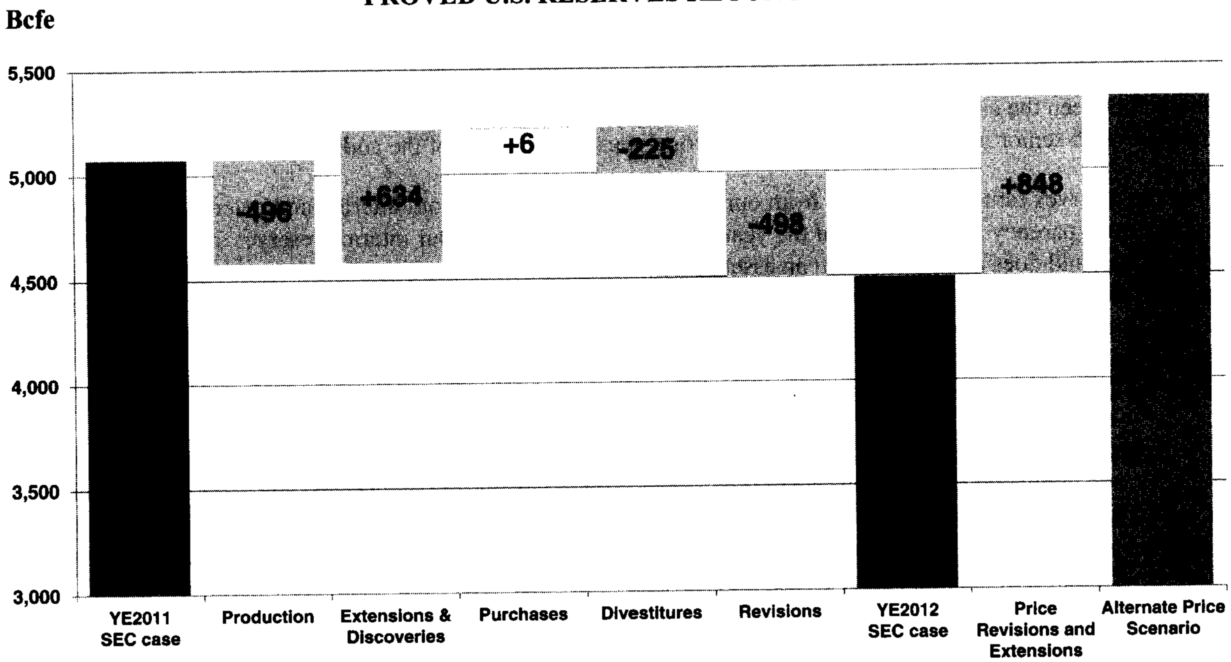
The following table shows domestic proved reserves utilizing the 2012 SEC case compared with an Alternate Price Scenario. Both of these cases assume that proved undeveloped reserves are drilled within five years. No changes were made to operating costs assumptions in the Alternate Price Scenario. Total capital expenditures would be increased by $1,035 million associated with 600 Bcfe of additional proved undeveloped locations in the Alternate Price Scenario.

	2012 SEC case				Alternate Price Scenario			
	Gas MMcf	NGL Mbbl	Oil Mbbl	Equivalent MMcfe	Gas MMcf	NGL Mbbl	Oil Mbbl	Equivalent MMcfe
Piceance Basin	2,338,554	103,094	8,755	3,009,650	2,772,549	124,204	11,025	3,583,927
Bakken Shale	34,074	6,790	67,463	479,593	34,303	6,835	67,911	482,775
Marcellus Shale	322,400	—	—	322,400	389,319	—	—	389,319
Powder River Basin	235,127	17	110	235,890	324,303	17	111	325,072
San Juan Basin	419,967	458	78	423,182	526,062	565	77	529,915
Other	18,951	—	141	19,792	26,539	—	200	27,736
Total Proved-Domestic	3,369,073	110,359	76,547	4,490,507	4,073,075	131,621	79,324	5,338,744

Total domestic proved reserves increase by 848 Bcfe in the Alternate Price Scenario as compared to the 2012 SEC case.

Proved reserves reconciliation

PROVED U.S. RESERVES RECONCILIATION



The 634 Bcfe of Extensions and Discoveries reflects 225 Bcfe added for drilled locations and 405 Bcfe added for new proved undeveloped locations. The extensions and discoveries were primarily in the Williston Basin, Appalachia Basin and Piceance Basin. The 225 Bcfe of Divestitures primarily represents the holdings in the Barnett Shale and Arkoma Basin that were sold in 2012. The overall negative revisions of 498 Bcfe reflects 572 Bcfe that were uneconomic due to the decline in the 12-month average natural gas and natural gas liquids price partially offset by a net increase related to proved undeveloped locations under the SEC five year rule. The 848 Bcfe related to Price Revisions and Extensions in the table above represents 600 Bcfe related to proved locations at year-end 2011 that were uneconomic under the prices used for the year-end 2012 reserves and additional proved undeveloped locations associated with our 2012 drilling program that are economic at the Alternate Price Scenario. The remaining amount relates to the extension of the productive life of proved reserves at December 31, 2012 under the Alternate Price Scenario.

Reserves estimation process

Our reserves are estimated by deterministic methods using 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 pervasiveness of our tight-sands, shale and coal bed methane reservoirs is established by combinations of subsurface analysis and analysis of 2D and 3D seismic data 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 NSAI and the asset teams to successfully complete the 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 NSAI 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 NSAI. In early December, reserves are reviewed with senior management. The process concludes upon receipt of the audit letter from NSAI.

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 as appropriate. The compensation of our reserves analysis team is not directly linked to reserves additions or revisions except to the extent that reserves additions are a component of our all-employee incentive plan.

Approximately 99 percent of our total year-end 2012 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 NSAI estimates. NSAI is satisfied with our methods and procedures in preparing the December 31, 2012 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 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 30 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

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 general, 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, 2012, our proved undeveloped reserves were 1,788 Bcfe, a decrease of 271 Bcfe over our December 31, 2011 proved undeveloped reserves estimate of 2,059 Bcfe. During 2012, 220 Bcfe of our December 31, 2011 proved undeveloped reserves were converted to proved developed reserves at a cost of $333 million. An additional 250 Bcfe of proved developed reserves was added to total proved reserves due to the development of unproved locations. As of 2012 year-end, we have reclassified a 143 Bcfe from proved to probable reserves due to the SEC five year rules. An additional 534 Bcfe that were uneconomic at 12-month average pricing used in 2012 were also reclassified from proved. Combined additions and revisions of proved undeveloped drillings locations were 692 Bcfe of which 405 Bcfe were additions or extensions of previously unproved locations and the remainder was primarily due to the restoration of reserves that were reclassified to probable reserves in prior years due to the SEC five year rules. These reclassified reserves under the SEC five year rule are predominately in the Piceance Basin where we have a large inventory of drilling locations. Additionally, our divestiture in 2012 of our holdings in the Barnett Shale and Arkoma Basin accounted for a 48 Bcfe decline in proved undeveloped reserves.

All proved undeveloped locations are scheduled to be spud within the next five years.

Oil and Gas Production, Production Prices and Production Costs

The following table summarizes our net production sales for the years indicated.

	Year Ended December 31,		
	2012	2011	2010
Production Sales Data:			
Natural Gas (MMcf)			
U.S.			
Piceance Basin	246,179	247,700	230,279
Other(a)	151,303	141,080	141,210
International(b)	7,061	7,389	7,088
Total	404,543	396,169	378,577
NGLs (Mbbls)			
U.S.			
Piceance Basin	10,075	9,902	8,003
Other(a)	317	155	51
International(b)	181	183	162
Total	10,573	10,240	8,216
Oil (Mbbls)			
U.S.	4,394	2,651	828
International(b)	2,178	2,054	1,980
Total	6,572	4,705	2,808
Combined Equivalent Volumes (MMcfe)(b)	507,416	485,840	444,720
Combined Equivalent Volumes (Mboe)	84,569	80,973	74,121
Average Daily Combined Equivalent Volumes (MMcfe/d)			
U.S.			
Piceance Basin	852	855	775
Other(a)	476	419	388
International(b)	58	57	55
Total	1,386	1,331	1,218

(a) Excludes production from our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.

(b) Includes approximately 69 percent of Apco's production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

The following tables summarize our domestic sales price and cost information for the years indicated.

	Year Ended December 31,		
	2012	2011	2010
Domestic realized average price per unit(a):			
Natural gas, without hedges (per Mcf)	$ 2.32	$ 3.48	$ 3.68
Impact of hedges (per Mcf)	1.06	0.84	0.90
Natural gas, with hedges (per Mcf)	$ 3.38	$ 4.32	$ 4.58
NGL, without hedges (per Bbl)	$28.56	$40.17	$35.02
Impact of hedges (per Bbl)	—	—	—
NGL, with hedges (per Bbl)	$28.56	$40.17	$35.02
Oil, without hedges (per Bbl)	$83.35	$84.91	$65.93
Impact of hedges (per Bbl)	2.23	0.39	—
Oil, with hedges (per Bbl)	$85.58	$85.30	$65.93
Price per Boe, without hedges(b)	$19.57	$25.56	$24.06
Price per Boe, with hedges(b)	$24.91	$29.78	$28.76
Price per Mcfe, without hedges(b)	$ 3.26	$ 4.26	$ 4.01
Price per Mcfe, with hedges(b)	$ 4.15	$ 4.96	$ 4.79

(a) Excludes our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.
(b) Realized average prices reflect realized market prices, net of fuel and shrink.

	Year Ended December 31,		
	2012	2011	2010
Domestic expenses per Mcfe(a):			
Operating expenses:			
Lifting costs and workovers	$0.44	$0.43	$0.41
Facilities operating expense	0.03	0.03	0.12
Other operating and maintenance	0.05	0.05	0.04
Total LOE	$0.52	$0.51	$0.57
Gathering, processing and transportation charges	1.04	1.05	0.75
Taxes other than income	0.18	0.24	0.25
Production cost	$1.74	$1.80	$1.57
General and administrative	$0.56	$0.57	$0.55
Depreciation, depletion and amortization	$1.93	$1.89	$1.87

(a) Excludes our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.

Productive Oil and Gas Wells

The table below summarizes 2012 productive wells by area(a).

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance Basin	4,494	4,101	—	—
Bakken Shale	—	—	101	62
Marcellus Shale	114	65	—	—
Powder River Basin	5,114	2,212	—	—
San Juan Basin	3,288	887	—	—
Other(b)	1,067	26	—	—
Total	14,077	7,291	101	62

(a) 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.
(b) Other includes Green River Basin and miscellaneous smaller properties.

At December 31, 2012, there were 233 gross and 110 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2012.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance Basin	126,763	99,683	159,035	117,146	285,798	216,829
Bakken Shale	56,846	51,478	34,361	32,727	91,207	84,205
Marcellus Shale	25,669	17,670	123,968	96,397	149,637	114,067
Powder River Basin	641,273	291,287	246,282	107,183	887,555	398,470
San Juan Basin	228,516	114,781	48,409	40,691	276,925	155,472
Other(a)	24,312	3,171	218,312	150,719	242,624	153,890
Total	1,103,379	578,070	830,367	544,863	1,933,746	1,122,933

(a) Other includes Green River Basins, other Williston Basin acreage and miscellaneous smaller properties.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was 100 percent in 2012 and approximately 99 percent in both 2011 and 2010.

The following table summarizes the number of domestic wells drilled for the periods indicated.

	2012		2011		2010	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance Basin	239	208	385	361	398	360
Bakken Shale	41	27	25	20	—	—
Marcellus Shale	54	33	36	17	8	3
Powder River Basin	150	92	523	225	531	244
San Juan Basin	11	6	56	33	43	15
Other(a)	52	—	212	34	177	38
Productive, development	547	366	1,237	690	1,157	660
Productive, exploration	1	1	2	2	—	—
Total Productive	548	367	1,239	692	1,157	660
Dry, development	—	—	2	1	5	4
Dry, exploration	—	—	—	—	—	—
Total Drilled	548	367	1,241	693	1,162	664

(a) Other includes Green River Basin and miscellaneous smaller properties.

Total gross operated wells drilled were 423 in 2012, 758 in 2011 and 656 in 2010.

Present Activities

At December 31, 2012, we had ten gross (seven net) wells in the process of being drilled. As previously noted in Significant Properties, we also have a large number of wells that are awaiting completion.

Scheduled Lease Expirations

Domestic. The table below sets forth, as of December 31, 2012, the gross and net acres scheduled to expire over the next several years. The acreage will not expire if we are able to establish production by drilling wells on the lease prior to the expiration date. We expect to hold substantially all of the Bakken Shale acreage by drilling prior to its expiration. We expect to hold most of the Marcellus Shale acreage through a combination of drilling, lease extensions and renewals.

	2013	2014	2015	2016 +	Total
Piceance Basin	3,157	15,599	778	13,716	33,250
Bakken Shale	3,404	874	40	979	5,297
Marcellus Shale	38,467	11,567	22,636	29,516	102,186
Powder River Basin	13,647	1,879	—	1,706	17,232
San Juan Basin	—	—	—	8,163	8,163
Other	14,961	30,083	12,458	82,085	139,587
Total (Gross Acres)	73,636	60,002	35,912	136,165	305,715

	2013	2014	2015	2016 +	Total
Piceance Basin	2,047	8,323	399	12,081	22,850
Bakken Shale	3,346	491	20	979	4,836
Marcellus Shale	29,386	8,227	19,668	22,461	79,742
Powder River Basin	6,722	933	—	872	8,527
San Juan Basin	—	—	—	8,163	8,163
Other	14,164	29,350	12,213	82,085	137,812
Total (Net Acres)	55,665	47,324	32,300	126,641	261,930

International. In general, all of our concessions have expiration dates of either 2025 or 2026, except for two concessions that expire beyond 2030 and four that expire in 2015 and 2016. With respect to these four, we are negotiating ten-year extensions for which we have contractual rights. These four concessions represent approximately 169,000 acres net to Apco or approximately 116,000 acres net to WPX based on our 69 percent ownership in Apco. Our remaining properties in Argentina and Colombia are all exploration permits or exploration contracts that have much shorter terms and on which we have made exploration investment commitments that must be completed. These areas will expire between 2013 and 2017 unless discoveries are made. There are opportunities to extend exploration terms for a year with good technical justification. We can either declare the portions of these blocks where we have made discoveries commercial and convert that acreage to a concession or exploitation acreage with a specified term for production of 25 to 35 years, or relinquish a portion or the balance of the acreage if we are not willing to make further exploration commitments.

Gas Management

Our sales and marketing activities include the sale of our natural gas, NGL and oil production along with third party purchases and sales of natural gas, which includes natural gas purchased from working interest owners in operated wells and other area third party producers. Through May 1, 2012, this activity included sales of natural gas to Williams Partners for use in its midstream business. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related price risk management activity. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in oil and gas revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Delivery Commitments

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of natural 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, generates ample production to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of natural gas is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure. This obligation expires in 2014.

Purchase Commitments

In December 2010, we agreed to buy up to 200,000 MMBtu/d of natural gas at Transco Station 515 (Marcellus Shale) priced at market prices from a third party. Purchases under the 12-year contract began in January 2012. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Seasonality

Generally, the demand for natural gas decreases during the spring and fall months and increases during the winter months and in some areas during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Conversely, during extreme weather events such as blizzards, hurricanes, or heat waves, pipeline systems can become temporary constraints to supply meeting demand thus amplifying localized price spikes. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the warmer months. This can lessen seasonal demand fluctuations. World weather and resultant prices for liquefied natural gas can also affect deliveries of competing liquefied natural gas into this country from abroad, affecting the price of domestically produced natural gas. In addition, adverse weather conditions can also affect our production rates or otherwise disrupt our operations.

Hedging Activity

To manage the commodity price risk and volatility associated with owning producing natural gas, NGL and crude oil 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."

Customers

Oil, NGLs and natural gas production is sold through our sales and marketing activities to a variety of purchasers under various length contracts ranging from one day to multi-year at market based prices. Our third party customers include other producers, utility companies, power generators, banks, marketing and trading companies and midstream service providers. In 2012, natural gas sales to BP Energy Company accounted for approximately 10 percent of our consolidated revenues. During 2012, Williams accounted for 12 percent of our consolidated revenue. We believe that the loss of one or more of our current natural gas, oil or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

REGULATORY MATTERS

The oil and natural gas industry is extensively regulated by numerous federal, state, local and foreign authorities, including Native American tribes in the United States. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and NGLs are not currently regulated and are made at market prices.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities including seasonal wildlife closures;
- the employment of tribal members or use of tribal owned service businesses;
- the rates of production or "allowables;"
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the notice to surface owners and other third parties; and
- the use, maintenance and restoration of roads and bridges used during all phases of drilling and production.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, oil and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells, or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where we operate. Most states have an administrative agency that requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing natural gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with them. The FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under the FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting natural gas to point-of-sale locations.

Oil Sales and Transportation

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Operation on Native American Reservations

A portion of our leases are, and some of our future leases may be, regulated by Native American tribes. In addition to regulation by various federal, state, and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and Bureau of Land Management ("BLM"), and the Environmental Protection Agency ("EPA"), together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are often subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements, or delays in obtaining necessary approvals or permits pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

ENVIRONMENTAL MATTERS

Our operations are subject to numerous federal, state, local, Native American tribal and foreign laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), the Clean Water Act ("CWA") and the Clean Air Act ("CAA"). These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, EPA's 2011 – 2013 National Enforcement Initiatives include Energy Extraction and "Assuring Energy Extraction Activities Comply with Environmental

Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

Hazardous Substances and Wastes. CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act ("RCRA") generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the CWA, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges. The CWA and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. On February 16, 2012, the EPA issued the final 2012 construction general permit ("CGP") for stormwater discharges from construction activities involving more than one acre, which will provide coverage for a five year period. The 2012 CGP modifies the prior CGP to implement the new Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The new rule includes new and more stringent restrictions on erosion and sediment control, pollution prevention and stabilization, although a numeric turbidity limit for certain larger construction sites has been stayed as of January 4, 2011.

Air Emissions. The CAA and associated state laws and regulations restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases ("GHGs") have been developed by the EPA and may increase the costs of compliance for some facilities. In 2012, the EPA issued federal regulations affecting our operations under the New Source Performance Standards ("NSPS") provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants ("NESHAP"), although implementation of some of the more rigorous requirements is not required until 2015.

Oil Pollution Act. The Oil Pollution Act of 1990, as amended ("OPA") and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act. The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety. The Occupational Safety and Health Act ("OSHA") and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Safe Drinking Water Act. The Safe Drinking Water Act ("SDWA") and comparable state statutes restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. We ordinarily use hydraulic fracturing as a means to maximize the productivity of our oil and gas wells in all of the domestic basins in which we operate. Our net acreage position in the basins in which hydraulic fracturing is utilized total approximately 690,000 acres and represents approximately 64 percent of our domestic proved undeveloped oil and gas reserves. Although average drilling and completion costs for each basin will vary, as will the cost of each well within a given basin, on average approximately 30 percent of the drilling and completion costs for each of our wells for which we use hydraulic fracturing is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget.

The protection of groundwater quality is extremely important to us. We follow applicable standard industry practices and legal requirements for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), which conduct many inspections during operations that include hydraulic fracturing. Industry standards and legal requirements for groundwater protection focus on six principal areas: (i) pressure testing of well construction and integrity, (ii) lining of pits used to hold water and other fluids used in the drilling process isolated from surface water and groundwater, (iii) casing and cementing practices for wells to ensure separation of the production zone from groundwater, (iv) disclosure of the chemical content of fracturing liquids, (v) setback requirements as to the location of waste disposal areas, and (vi) pre- and post-drilling groundwater sampling. The legal requirements relating to the protection of surface water and groundwater vary from state to state and there are also federal regulations and guidance that apply to all domestic drilling. In addition, the American Petroleum Institute publishes industry standards and guidance for hydraulic fracturing and the protection of surface water and groundwater. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing.

In addition to the required use of and specifications for casing and cement in well construction, we observe regulatory requirements and what we consider best practices to ensure wellbore integrity and full isolation of any underground aquifers and protection of surface waters. These include the following:

- Prior to perforating the production casing and hydraulic fracturing operations, the casing is pressure tested.
- Before the fracturing operation commences, all surface equipment is pressure tested, which includes the wellhead and all pressurized lines and connections leading from the pumping equipment to the wellhead. During the pumping phases of the hydraulic fracturing treatment, specialized equipment is utilized to monitor and record surface pressures, pumping rates, volumes and chemical concentrations

to ensure the treatment is proceeding as designed and the wellbore integrity is sound. Should any problem be detected during the hydraulic fracturing treatment, the operation is shut down until the problem is evaluated, reported and remediated.

- As a means to protect against the negative impacts of any potential surface release of fluids associated with the hydraulic fracturing operation, special precautions are taken to ensure proper containment and storage of fluids. For example, any earthen pits containing non-fresh water must be lined with a synthetic impervious liner. These pits are tested regularly, and in certain sensitive areas have additional leak detection systems in place. At least two feet of freeboard, or available capacity, must be present in the pit at all times. In addition, earthen berms are constructed around any storage tanks, any fluid handling equipment, and in some cases around the perimeter of the location to contain any fluid releases. These berms are considered to be a "secondary" form of containment and serve as an added measure for the protection of groundwater.
- We conduct baseline water monitoring in many of the basins in which we use hydraulic fracturing:
- In Colorado, baseline water monitoring is required by the Colorado Oil and Gas Conservation Commission ("COGCC") and may be required by BLM as a condition of approval for the drilling permit.
- In Pennsylvania, we perform baseline water monitoring pursuant to Pennsylvania Department of Environmental Protection requirements.
- There are currently no regulatory requirements to conduct baseline water monitoring in the Bakken Shale or the New Mexico portion of our San Juan Basin assets. We plan to begin voluntarily conducting water monitoring in the Bakken Shale. The majority of our assets in the San Juan Basin are on federal lands, and there are few cases where water wells are within one to two miles of our wells, which is outside the range that we would typically sample.

Once a pipe is set in place, cement is pumped into the well where it hardens and creates a permanent, isolating barrier between the steel casing pipe and surrounding geological formations. This aspect of the well design essentially eliminates a "pathway" for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. Furthermore, in the basins in which we conduct hydraulic fracturing, the hydrocarbon bearing formations are separated from any usable underground aquifers by thousands of feet of impermeable rock layers. This wide separation serves as a protective barrier, preventing any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones.

In addition, the vendors we employ to conduct hydraulic fracturing are required to monitor all pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis and data is recorded to ensure protection of groundwater.

The cement and steel casing used in well construction can have rare failures. Any failure in isolation is reported to the applicable oil and gas regulatory body. A remediation procedure is written and approved and then completed on the well before any further operations or production is commenced. Possible isolation failures may result from:

- *Improper cementing work.* This can create conditions in which hydraulic fracturing fluids and other natural occurring substances can migrate into the surrounding geological formation. Production casing cementing tops and cement bond effectiveness are evaluated using either a temperature log or an acoustical cement bond log prior to any completion operations. If the cement bond or cement top is determined to be inadequate for zone isolation, remedial cementing operations are performed to fill any voids and re-establish integrity. As part of this remedial operation, the casing is again pressure tested before fracturing operations are initiated.
- *Initial casing integrity failure.* The casing is pressure tested prior to commencing completion operations. If the test fails due to a compromise in the casing, the applicable oil and gas regulatory body will be notified and a remediation procedure will be written, approved and completed before any further operations are conducted. In addition, casing pressures are monitored throughout the fracturing treatment and any indication of failure will result in an immediate shutdown of the operation.

- *Well failure or casing integrity failure during production.* Loss of wellbore integrity can occur over time even if the well was correctly constructed due to downhole operating environments causing corrosion and stress. During production, the bradenhead, casing and tubing pressures are monitored and a casing failure can be identified and evaluated. Remediation could include placing additional cement behind casing, installing a casing patch, or plugging and abandoning the well, if necessary.
- *"Fluid leakoff" during the fracturing process.* Fluid leakoff can occur during hydraulic fracturing operations whereby some of the hydraulic fracturing fluid flows through the artificially created fractures into the micropore or pore spaces within the formation, existing natural factures in the formation, or small fractures opened into the formation by the pressure in the induced fracture. Fluid leakoff is accounted for in the volume design of nearly every fracturing job and "pump-in" tests are often conducted prior to fracturing jobs to estimate the extent of fluid leakoff. In certain situations, a very fine grain sand is added in the initial part of the treatment to seal-off any small fractures of micropore spaces and mitigate fluid leak-off.

Approximately 99 percent of hydraulic fracturing fluids are made up of water and sand. We utilize major hydraulic fracturing service companies whose research departments conduct ongoing development of "greener" chemicals that are used in fracturing. We evaluate, test, and where appropriate adopt those products that are more environmentally friendly. We have also chosen to participate in a voluntary fracturing chemical registry that is a public website: *www.fracfocus.org* at which interested persons can find out information about fracturing fluids. This registry is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission and provides our industry with an avenue to voluntarily disclose chemicals used in the hydraulic fracturing process. The Company registered with the FracFocus Chemical Disclosure Registry in April 2011 and began uploading data when the registry went live on April 11, 2011. To date, we have loaded data on more than 800 wells, including data relating to wells fractured since January 1, 2011, to the site. Consistent with other industry participants, we are not planning to add data on wells drilled prior to 2011. The information included on this website is not incorporated by reference in this Annual Report on Form 10-K.

In 2012, we used 100 percent recycled water for our hydraulic fracturing operations in our largest area of development, the Piceance Basin. This recycling process lessens the demand on local natural water resources. Any water that is recovered in our operations that is not used for our hydraulic fracturing operations is safely disposed in accordance with the state and federal rules and regulations in a manner that does not impact underground aquifers and surface waters. In the Marcellus, we use a blend of recycled water from our hydraulic fracturing operations with water from natural sources.

Despite our efforts to minimize impacts on the environment from hydraulic fracturing activities, in light of the volume of our hydraulic fracturing activities, we have occasionally been engaged in litigation and received requests for information, notices of alleged violation, and citations related to the activities of our hydraulic fracturing vendors, none of which has resulted in any material costs or penalties.

Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate have considered Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") bills and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection

Control Program, and on May 10, 2012, the EPA published its proposed guidance on the issue. The public comment period for the proposed permitting guidance closed on August 23, 2012, and the EPA has yet to issue any final guidance. On October 21, 2011, the EPA announced its intention to propose regulation by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The results of this study, which are expected to be published in a draft report for public and peer review in 2014, could result in additional regulations, which could lead to operational burdens similar to those described above. In connection with the EPA study, we have received and responded to a request for information from the EPA for 52 of our wells located in various basins that have been hydraulically fractured. The requested information covers well design, construction and completion practices, among other things. We understand that similar requests were sent to eight other companies that own or operate wells that utilized hydraulic fracturing.

In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011. The report concludes that the risk of fracturing fluids contaminating drinking water sources through fractures in the shale formations "is remote." It also states that development of the nation's shale resources has produced major economic benefits. The report includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The Government Accountability Office is also examining the environmental impacts of produced water and the Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. The United States Department of the Interior is also considering whether to impose disclosure requirements or other mandates for hydraulic fracturing on federal land.

Several states, including Pennsylvania, Colorado, North Dakota, New Mexico and Wyoming, have adopted or are considering adopting, regulations that could restrict or impose additional requirements related to hydraulic fracturing. For example, on December 13, 2011, the Texas Railroad Commission adopted Statewide Rule 29, which requires public disclosure of the chemicals that operators use during hydraulic fracturing in Texas for all operators that receive a permit on or after February 1, 2012. Pennsylvania also requires that detailed information be disclosed regarding the hydraulic fracturing fluids, including but not limited to, a list of chemical additives, volume of each chemical added, and list of chemicals in the material safety data sheets. Since June 2009, Colorado has required all operators to maintain a chemical inventory by well site for each chemical product used downhole or stored for use downhole during drilling, completion and workover operations, including fracture stimulation in an amount exceeding 500 pounds during any quarterly reporting period. Colorado adopted its final hydraulic fracturing chemical disclosure rules on December 13, 2011. Wyoming requires public disclosure of chemicals used in hydraulic fracturing. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. A number of states have also adopted regulations increasing the setback requirements, or are in the process of rulemaking to address the issue, including Colorado, New Mexico and Pennsylvania.

In addition, a number of local governments in Colorado have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities, while some state and local governments in the Marcellus Shale and San Juan Basin in New Mexico have considered or imposed temporary moratoria on drilling operations using hydraulic fracturing until further study of the potential environmental and human health impacts by the EPA or the relative state agencies are completed. Additionally, publicly operated treatment works facilities in Pennsylvania have ceased taking wastewater from hydraulic fracturing operations, and we are now recycling this wastewater and utilizing it in subsequent hydraulic fracturing operations. At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

Global Warming and Climate Change. Recent scientific studies have suggested that emissions of GHGs, including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. Both houses of Congress have previously considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The EPA has begun to regulate GHG emissions. On December 7, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public heath and the environment. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA issued a final rule that went into effect in 2011 that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions. On November 30, 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage, and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, and our reporting began in 2012 for emissions occurring in 2011. We are required to report our GHG emissions under this rule but are not subject to GHG permitting requirements. Several of the EPA's GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact our operations. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources and may increase our litigation risk for such claims. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Foreign Operations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries. For example, the Argentine Department of Energy and the government of the provinces in which Apco's oil and gas producing concessions are located have environmental control policies and regulations that must be adhered to when conducting oil and gas exploration and exploitation activities. Future environmental regulation of certain aspects of our operations in Argentina and Colombia that are currently unregulated and changes in the laws or regulations could materially affect our financial condition and results of operations.

COMPETITION

We compete 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 management 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.

EMPLOYEES

At December 31, 2012 , we had approximately 1,200 full-time employees.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Item 8—Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 17 of our Notes to Consolidated Financial Statements for financial information with respect to our segments' revenues, profits or losses, and total assets.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Item 8—Financial Statements and Supplementary Data—Note 17 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 17 of the 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.

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We make available free of charge through our website, *www.wpxenergy.com/investors*, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, other reports filed under the Securities Exchange Act of 1934 ("Exchange Act") and all amendments to those reports simultaneously or as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Our reports are also available free of charge on the SEC's website, *www.sec.gov*. You may inspect and copy our reports at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the Public Reference Room. Also available free of charge on our website are the following corporate governance documents:

- Amended and Restated Certificate of Incorporation
- Restated Bylaws
- Corporate Governance Guidelines
- Code of Business Conduct, which is applicable to all WPX Energy directors and employees, including the principal executive officer, the principal financial officer and the principal accounting officer
- Audit Committee Charter
- Compensation Committee Charter
- Nominating and Governance Committee Charter

All of our reports and corporate governance documents may also be obtained without charge by contacting Investor Relations, WPX Energy, Inc., One Williams Center, Tulsa, Oklahoma 74172.

We maintain an Internet site at www.wpxenergy.com. We do not incorporate our Internet site, or the information contained on that site or connected to that site, into this Annual Report on Form 10-K.

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 Annual Report on Form 10-K include forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. 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.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "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;
- Acquisitions or divestitures
- Seasonality of our business; and
- Natural gas, natural gas liquids ("NGLs") 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 regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- 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; and
- Other factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business."

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements set forth above. 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. Forward-looking statements speak only as of the date they are made. We disclaim any obligation 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, except to the extent required by applicable laws. If we update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements.

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 "Risk Factors."

RISK FACTORS

You should carefully consider each of the following risks, which we believe are the principal risks that we face and of which we are currently aware, and all of the other information in this report. Some of the risks described below relate to our business, while others relate to our separation from Williams. Other risks relate principally to the securities markets and ownership of our common stock. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could suffer materially and adversely. In that case, the trading price of our common stock could decline, and you might lose all or part of your investment.

Risks Related to Our Business

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. We expect to fund our capital expenditures through a combination of cash flows from operations and, when appropriate, borrowings under our credit facility. 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 have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our natural gas and oil production or reserves, and in some areas a loss of properties.

Failure to replace reserves may negatively affect our business.

The growth of our 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 always be able to find, develop or acquire additional reserves at acceptable costs. 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. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The new wells we drill or participate in may not be commercially productive, and we may not recover all or any portion of our investment in wells we drill or participate in. 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. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed, canceled or rendered unprofitable or less profitable than anticipated as a result of a variety of other factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, supplies, skilled labor, capital or transportation;
- Equipment failures or accidents;
- Adverse weather conditions, such as floods or blizzards;
- Title and lease related problems;

- Limitations in the market for natural gas and oil;
- Unexpected drilling conditions or problems;
- Pressure or irregularities in geological formations;
- Regulations and regulatory approvals;
- Changes or anticipated changes in energy prices; or
- Compliance with environmental and other governmental requirements.

If natural gas and oil prices decrease, we may be required to take write-downs of the carrying values of our natural gas and oil properties.

Accounting rules require that we review periodically the carrying value of our natural gas and oil properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our natural gas and oil properties. A writedown constitutes a non-cash charge to earnings. For example, as a result of annual and interim assessments for impairments of our proved and unproved properties and due to significant declines in forward natural gas prices, we recorded impairments of capitalized costs of certain natural gas properties of $225 million in 2012. In addition to those long-lived assets for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included other domestic producing properties and costs of acquired unproved reserves, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For the other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately three percent could be at risk for impairment if forward prices across all future periods decline by approximately 11 percent to 12 percent, on average, as compared to the forward commodity prices at December 31, 2012. We estimate that approximately 31 percent could be at risk for impairment if forward commodity prices across all periods decline by approximately 16 percent to 18 percent. A substantial portion of the remaining carrying value of these other assets (primarily related to assets in the Piceance Basin) could be at risk for impairment if forward prices across all future periods decline by approximately 23 percent, on average, as compared to the prices at December 31, 2012 . We may incur impairment charges for these or other properties in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

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

Reserve estimation is a subjective process of evaluating 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 NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 40 percent of our total estimated proved reserves at December 31, 2012 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

The present value of future net revenues from our proved reserves will not necessarily be the same as the value we ultimately realize of our estimated natural gas and oil reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our natural gas and oil properties will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Certain of our domestic undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The majority of our acreage in the Marcellus Shale is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If we do not extend our leases and our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory and lease issues.

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

Our revenues, operating results, future rate of growth and the value of our business depend primarily upon the prices of natural gas, oil and NGLs. Price volatility can impact both the amount we receive for our products and the volume of products we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money under our credit facility or raise additional capital.

The markets for natural gas, oil and NGLs 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:

- Weather conditions;
- The level of consumer demand;
- The overall economic environment;
- Worldwide and domestic supplies of and demand for natural gas, oil and NGLs;
- 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;
- Variations in local market conditions (basis differential);
- 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 quantity of foreign imports of natural gas and oil;
- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas and oil markets;
- The credit of participants in the markets where products are bought and sold; and
- The adoption of regulations or legislation relating to climate change.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities.

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Bakken Shale and Marcellus Shale or that we will be able to obtain sufficient transportation capacity on economic terms.

A lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

We may have excess capacity under our firm transportation contracts, or the terms of certain of those contracts may be less favorable than those we could obtain currently.

We have entered into contracts for firm transportation that may exceed our transportation needs. Any excess transportation commitments will result in excess transportation costs that could negatively affect our results of operations. In addition, certain of the contracts we have entered into may be on terms less favorable to us than we could obtain if we were negotiating them at current rates, which also could negatively affect our results of operations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues or increase our costs. As of December 31, 2012 , we were not the operator of approximately 14 percent of our total domestic net production. Apco generally has outside-operated interests in its properties. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

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 includes wholesale contracts to buy and sell natural gas, oil and NGLs that are settled by the delivery of the commodity or cash. 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 business, we often extend credit to our counterparties. 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.

Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.

The systems we use to quantify commodity price risk associated with our businesses 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. Furthermore, no single hedging arrangement can adequately address all commodity price 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.

Our use of derivatives 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 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 natural gas, oil and NGLs 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 natural gas, oil or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

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 "Dodd-Frank Act") was enacted. Among other reasons, the Dodd-Frank Act was enacted to establish federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions in the major energy markets, including swaps, hedging and other transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring that certain transactions be cleared on exchanges, for which transactions cash or other liquid collateral will be required. Moreover, certain of the transactions required to be cleared will have to be executed on boards of trade. The position limits rule was vacated by the United States District Court for the District of Columbia in September of 2012, although the Commodities Futures Trading Commission ("CFTC") has stated that it will appeal the District Court's decision.

The final impact of the Dodd-Frank Act on our hedging activities is uncertain at this time due to the fact that the SEC, the CFTC and other federal regulatory bodies that have involvement in this area have yet to complete the rules and regulations implementing the new legislation. Although we believe the derivative contracts that we enter into should not be impacted by position limits and that we should generally be eligible to elect the exception from any requirement to clear our hedging transactions through a central exchange, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC and other federal regulators, among other factors.

Depending on the rules adopted by the CFTC and other federal regulatory bodies, the cost of entering into and maintaining derivative contracts could significantly increase, including from costs associated with swap recordkeeping and reporting requirements, and because we might in the future be required to provide cash or other liquid collateral for our commodities hedging transactions under circumstances in which we do not currently do so. Posting of such additional cash or illiquid collateral could impact our liquidity and reduce our cash available for capital expenditures and reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. The Dodd-Frank Act and related swaps regulations could materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. To the extent we do enter into derivatives transactions, the Dodd-Frank Act and the related swaps regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties and therefore increase our exposure to less creditworthy parties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and may be otherwise adversely affected and our cash flows may be less predictable.

Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

We are exposed to the credit risk of our customers and counterparties, 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 and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, 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.

We face competition in acquiring new properties, marketing natural gas and oil and securing equipment and trained personnel in the natural gas and oil industry.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and oil and securing equipment and trained personnel. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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 oil and the fractionation and storage of NGLs, including:

- Hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines, pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), oil, NGLs, brine or industrial chemicals;
- Operator error;
- Pollution and environmental risks;
- Fires, explosions and blowouts;
- Risks related to truck and rail loading and unloading; and
- 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.

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 that 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.

Although we maintain property insurance on certain physical assets that we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets. 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. 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.

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 and reserves disclosures and companies' relationships with their independent public accounting firms and reserves consultants. 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 or the SEC could enact new accounting standards 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, principally in Argentina and Colombia. The economic, political and legal conditions and regulatory environment in the countries in which we have interests or in which we might pursue acquisition or investment opportunities present risks that are different from or greater than those in the United States. These risks include 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, including with respect to the prices we realize for the commodities we produce and sell. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments 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.

In 2012, the Argentine government asserted that certain exploration and production companies operating in Argentina had not invested sufficiently to overcome Argentina's domestic production declines, thereby leading to reduced levels of oil and natural gas production as well as reductions in oil and natural gas proved reserves. On that basis, six provinces rescinded certain of Repsol YPF S.A.'s ("YPF") and other producers' concessions. In addition, the federal government expropriated a majority interest in YPF, the largest oil producing company in Argentina. If the government subjectively determines that we have not sufficiently invested in our properties, it could take action with regard to our concessions before our contract terms expire.

Our operating results might fluctuate on a seasonal and quarterly basis.

Our revenues 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 the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

Our debt agreements impose restrictions on us that may limit our access to credit and adversely affect our ability to operate our business.

Our credit facility contains various covenants that restrict or limit, among other things, our ability to grant liens to support indebtedness, merge or sell substantially all of our assets, make investments, loans or advances and enter into certain hedging agreements, make certain distributions, incur additional debt and enter into certain affiliate transactions. In addition, our credit facility contains financial covenants and other limitations with which we will need to comply and which may limit our ability to borrow under the facility. Similarly, the indenture governing the Notes restricts our ability to grant liens to secure certain types of indebtedness and merge or sell substantially all of our assets. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired.

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance our debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

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

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers and reduced access to credit markets. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases ("GHGs") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

In addition, legislative and regulatory responses related to GHGs and climate change create the potential for financial risk. The U.S. Congress has previously considered legislation and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

Numerous states have announced or adopted programs to stabilize and reduce GHGs, as well as their own reporting requirements. On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. On November 8, 2010, the EPA also issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year—the Greenhouse Gas Reporting Program ("GHGRP"). The rule requires reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule. The EPA publishes the data on its website. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities that could exceed current expectations.

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations inherent in drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- Clean Air Act ("CAA") and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act ("CWA"), and analogous state laws, which regulate discharge of wastewaters and storm water from some our facilities into state and federal waters, including wetlands;
- Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- Resource Conservation and Recovery Act ("RCRA"), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities;
- National Environmental Policy Act ("NEPA"), which requires federal agencies to study likely environment impacts of a proposed federal action before it is approved, such as drilling on federal lands;
- Safe Drinking Water Act ("SDWA"), which restricts the disposal, treatment or release of water produced or used during oil and gas development;
- Endangered Species Act ("ESA"), and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and
- Oil Pollution Act ("OPA") of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulation of above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including the EPA, the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes Energy Extraction and "Assuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Our business may be adversely affected by increased costs due to stricter pollution control equipment requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

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

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations in order to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. Recently, there has been heightened debate about the hydraulic fracturing process and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. If adopted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing. The EPA published its "Status Report" in December 2012 and expects to publish results for public and peer review in 2014. On October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters.

Several states have adopted or considered legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic fracturing, including states in which we operate (e.g., Wyoming, Pennsylvania, Colorado, North Dakota and New Mexico). The U.S. Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

Our ability to produce gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations, particularly with respect to our Marcellus Shale, San Juan Basin, Bakken Shale and Piceance Basin operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

Legal and regulatory proceedings and investigations relating to the energy industry, and the complex government regulations to which our businesses are subject, have adversely affected our business and may continue to do so. The operation of our businesses might also be adversely affected by changes in regulations or in their interpretation or implementation, or the introduction of new laws, regulations or permitting requirements applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation or increased permitting requirements. Current legal proceedings or other matters against us, including environmental matters, suits, regulatory appeals, challenges to our permits by citizen groups and similar matters, might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations might be revised or reinterpreted, new laws, regulations and permitting requirements might be adopted or become applicable to us, our facilities, our customers, our vendors or our service providers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, several ruptures on third party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed, including new regulations covering gathering pipelines that have not previously been subject to regulation. Such reforms, if adopted, could significantly increase our costs.

Certain of our properties, including our operations in the Bakken Shale, are located on Native American tribal lands and are subject to various federal and tribal approvals and regulations, which may increase our costs and delay or prevent our efforts to conduct planned operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management ("BLM") and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to gas and oil operations on Native American tribal lands. These regulations and approval requirements relate to such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. In addition, if our relationships with any of the relevant Native American tribes were to deteriorate, we could face significant risks to our ability to continue the projected development of our leases on Native American tribal lands. One or more of these factors may increase our costs of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct, our natural gas or oil development and production operations on such lands.

Tax laws and regulations may change over time, including changes to certain federal income tax deductions currently available with respect to oil and gas exploration and production.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions for the periods for which the filings are made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation, it could have a material adverse effect on us.

President Obama has proposed changes to certain federal income tax provisions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) repeal of the percentage depletion allowance for oil and gas properties; (ii) elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; (iii) repeal of the manufacturing deduction for certain U.S. production activities; and (iv) extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition and results of operations.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- properties we acquire may be subject to burdens on title that we were not aware of at the time of acquisition or that interfere with our ability to hold the property for production;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

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

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Certain of our accounting services are currently provided by our outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which our outsourcing providers may provide services to us present similar risks of business operations located outside of the United States, including risks of interruption of business, 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.

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, it may not be available on commercially reasonable terms. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

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

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute natural gas, oil, or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

Risks Related to Our Separation from Williams

We may not realize the potential benefits from our separation from Williams.

We may not realize the benefits that we anticipated from our separation from Williams. These benefits include the following:

- allowing our management to focus its efforts on our business and strategic priorities;
- enhancing our market recognition with investors;
- providing us with direct access to the debt and equity capital markets;
- improving our ability to pursue acquisitions through the use of shares of our common stock as consideration; and
- enabling us to allocate our capital more efficiently.

We may not achieve the anticipated benefits from our separation for a variety of reasons. For example, although we have direct access to the debt and equity capital markets following the separation, we may not be able to issue debt or equity on terms acceptable to us or at all. The availability of shares of our common stock for use as consideration for acquisitions also will not ensure that we will be able to successfully pursue acquisitions or that the acquisitions will be successful. Moreover, even with equity compensation tied to our business we may not be able to attract and retain employees as desired. We also may not fully realize the anticipated benefits from our separation if any of the matters identified as risks in this "Risk Factors" section were to occur. If we do not realize the anticipated benefits from our separation for any reason, our business may be materially adversely affected.

We have a short operating history as an independent, publicly traded company, and our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical financial information that we have included in this report may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. We were not operated, as a separate, stand-alone company for each of the historical periods presented. The costs and expenses reflected in our historical financial information include an allocation for certain corporate functions historically provided by Williams, including executive oversight, cash management and treasury administration, financing and accounting, tax, internal audit, investor relations, payroll and human resources administration, information technology, legal, regulatory and government affairs, insurance and claims administration, records management, real estate and facilities management, sourcing and procurement, mail, print and other office services, and other services, that may be different from the comparable expenses that we would have incurred had we operated as a stand-alone company. These allocations were based on what we and Williams considered to be reasonable reflections of the historical utilization levels of these services required in support of our business. We have not adjusted our historical financial information to reflect changes that will occur in our cost structure and operations as a result of our transition to becoming a stand-alone public company, including changes in our employee base, potential increased costs associated with reduced economies of scale, the provision of letters of credit in lieu of Williams' guarantees to support certain contracts and increased costs associated with the SEC reporting and the NYSE requirements. Therefore, our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future. For additional information, see "Selected Historical Financial Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our financial statements and related notes included elsewhere in this report.

Our costs increase as a result of operating as a public company, and our management is required to devote substantial time to complying with public company regulations.

Prior to our separation from Williams, we operated our business as a segment of a public company. As a stand-alone public company, we incur additional legal, accounting, compliance and other expenses that we have not incurred historically. We are now obligated to file with the SEC annual and quarterly information and other reports that are specified in Section 13 and other sections of the Exchange Act. We are required to ensure that we have the ability to prepare financial statements that are fully compliant with all SEC reporting requirements on a timely basis. In addition, we are subject to other reporting and corporate governance requirements, including certain requirements of the NYSE, and certain provisions of Sarbanes-Oxley and the regulations promulgated thereunder, which will impose significant compliance obligations upon us.

Sarbanes-Oxley, as well as new rules subsequently implemented by the SEC and the NYSE, have imposed increased regulation and disclosure and required enhanced corporate governance practices of public companies. We are committed to maintaining high standards of corporate governance and public disclosure, and our efforts to comply with evolving laws, regulations and standards in this regard are likely to result in increased marketing, selling and administrative expenses and a diversion of management's time and attention from revenue-generating activities to compliance activities. These changes require a significant commitment of additional resources.

Our agreements with Williams require us to assume the past, present, and future liabilities related to our business and may be less favorable to us than if they had been negotiated with unaffiliated third parties.

We negotiated all of our agreements with Williams as a wholly-owned subsidiary of Williams. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us. Pursuant to the separation and distribution agreement, we have assumed all past, present and future liabilities (other than tax liabilities which will be governed by the tax sharing agreement as described herein) related to our business, and we will agree to indemnify Williams for these liabilities, among other matters. Such liabilities include unknown liabilities that could be significant. The allocation of assets and liabilities between Williams and us may not reflect the allocation that would have been reached between two unaffiliated parties.

We may increase our debt or raise additional capital in the future, which could affect our financial health, and may decrease our profitability.

We may increase our debt or raise additional capital in the future, subject to restrictions in our debt agreements. If our cash flow from operations is less than we anticipate, or if our cash requirements are more than we expect, we may require more financing. However, debt or equity financing may not be available to us on terms acceptable to us, if at all. If we incur additional debt or raise equity through the issuance of our preferred stock, the terms of the debt or our preferred stock issued may give the holders rights, preferences and privileges senior to those of holders of our common stock, particularly in the event of liquidation. The terms of the debt may also impose additional and more stringent restrictions on our operations than we currently have. If we raise funds through the issuance of additional equity, your ownership in us would be diluted. If we are unable to raise additional capital when needed, it could affect our financial health, which could negatively affect your investment in us.

If there is a determination that the spin-off is taxable for U.S. federal income tax purposes because the facts, assumptions, representations, or undertakings underlying the tax opinion are incorrect or for any other reason, then Williams and its stockholders could incur significant income tax liabilities, and we could incur significant liabilities.

The spin-off was conditioned on Williams' receipt of an opinion of its outside tax advisor reasonably acceptable to the Williams' Board of Directors to the effect that the spin-off would not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams, and Williams' stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of fractional shares. In addition, Williams received a private letter ruling in which the IRS made various rulings, including that the spin-off will not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams and Williams' stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of fractional shares. The private letter ruling and opinion relied on certain facts, assumptions, representations and undertakings from Williams and us regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Williams and its stockholders may not be able to rely on the private letter ruling or the opinion of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinion of Williams' tax advisor, the IRS could conclude upon audit that the spin-off is taxable in full or in part.

Our tax sharing agreement with Williams may limit our ability to take certain actions and may require us to indemnify Williams for significant tax liabilities.

Under the tax sharing agreement, we agreed to take reasonable action to ensure that the spin-off qualifies for tax-free status under section 355 and section 368(a)(1)(D) of the Internal Revenue Code of 1986 (the "Code"). We also gave representations and agreed to various other covenants in the tax sharing agreement intended to ensure the tax-free status of the spin-off. These covenants restrict our ability to execute certain transactions for a limited period of time following the spin-off without first consulting with Williams. For example, we will consult with Williams before we sell assets outside the ordinary course of business, issue or sell additional common stock (including securities convertible into our common stock), or enter into certain other corporate security transactions during this limited time period.

Further, under the tax sharing agreement, we are required to indemnify Williams against certain tax-related liabilities that may be incurred by Williams relating to the spin-off, to the extent caused by our breach of any representations or covenants made with respect to the spin-off. These liabilities include the substantial tax-related liability that would result if the spin-off of our stock to Williams' stockholders failed to qualify as a tax-free transaction.

We will not have complete control over our tax decisions and could be liable for income taxes owed by Williams.

For any tax periods ending on or before the spin-off, we and our U.S. subsidiaries were included in Williams' consolidated group for federal income tax purposes as well as any combined, consolidated or unitary tax returns of Williams for state or local income tax purposes. Under the tax sharing agreement, for each period in which we were consolidated or combined with Williams for purposes of any tax return, a pro forma tax return was prepared for us as if we filed our own consolidated, combined or unitary return, except that such pro forma tax return did not include any carryovers or carrybacks of losses or credits and was calculated without regard to the federal alternative minimum tax. For any adjustments to the pro forma tax returns following the spin-off we will reimburse Williams for any additional taxes shown on the pro forma tax returns, and Williams will reimburse us for reductions in the taxes shown on the pro forma tax returns. In addition, Williams will effectively control all of our tax decisions in connection with any Williams consolidated, combined or unitary income tax returns in which we are included. Thus Williams will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Williams and detrimental to us.

Moreover, notwithstanding the tax sharing agreement, U.S. federal law provides that each member of a consolidated group is liable for the group's entire tax obligation. Thus, to the extent Williams fails to make any U.S. federal income tax payments required by law, we could be liable for the shortfall with respect to periods prior to the spin-off. Similar principles may apply for foreign, state or local income tax purposes where we were included in combined, consolidated or unitary returns with Williams.

Third parties may seek to hold us responsible for liabilities of Williams that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of Williams. Under our agreements with Williams, Williams agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure you that we will be able to recover the full amount of our losses from Williams.

Our prior and continuing relationship with Williams exposes us to risks attributable to businesses of Williams.

Williams is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of Williams that are incurred through a breach of the separation and distribution agreement or any ancillary agreement by Williams or its affiliates other than us, or losses that are attributable to Williams in connection with the spin-off or are not expressly assumed by us under our agreements with Williams. Any claims made against us that are properly attributable to Williams in accordance with these arrangements would require us to exercise our rights under our agreements with Williams to obtain payment from Williams. We are exposed to the risk that, in these circumstances, Williams cannot, or will not, make the required payment.

Our directors and executive officers who own shares of common stock of Williams, or who hold options to acquire common stock of Williams or other Williams equity-based awards, may have actual or potential conflicts of interest.

Ownership of shares of common stock of Williams, options to acquire shares of common stock of Williams and other equity-based securities of Williams by certain of our directors and officers may create, or appear to create, potential conflicts of interest when those directors and officers are faced with decisions that could have different implications for Williams than they do for us.

The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements.

The spin-off is subject to review under various state and federal fraudulent conveyance laws. Under these laws, if a court in a lawsuit by an unpaid creditor or an entity vested with the power of such creditor (including without limitation a trustee or debtor-in-possession in a bankruptcy by us or Williams or any of our respective subsidiaries) were to determine that Williams or any of its subsidiaries did not receive fair consideration or reasonably equivalent value for distributing our common stock or taking other action as part of the spin-off, or that we or any of our subsidiaries did not receive fair consideration or reasonably equivalent value for incurring indebtedness, including the new debt incurred by us in connection with the spin-off, transferring assets or taking other action as part of the spin-off and, at the time of such action, we, Williams or any of our respective subsidiaries (i) was insolvent or would be rendered insolvent, (ii) had unreasonably small capital with which to carry on its business and all business in which it intended to engage or (iii) intended to incur, or believed it would incur, debts beyond its ability to repay such debts as they would mature, then such court could void the spin-off as a constructive fraudulent transfer. If such court made this determination, the court could impose a number of different remedies, including without limitation, voiding our liens and claims against Williams, or providing Williams with a claim for money damages against us in an amount equal to the difference between the consideration received by Williams and the fair market value of our company at the time of the spin-off.

The measure of insolvency for purposes of the fraudulent conveyance laws will vary depending on which jurisdiction's law is applied. Generally, however, an entity would be considered insolvent if the present fair saleable value of its assets is less than (i) the amount of its liabilities (including contingent liabilities) or (ii) the amount that will be required to pay its probable liabilities on its existing debts as they become absolute and mature. No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Williams or any of our respective subsidiaries were solvent at the time of or after giving effect to the spin-off, including the distribution of our common stock.

Under the separation and distribution agreement, each of Williams and we are responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to Williams, particularly if Williams were to refuse or were unable to pay or perform the subject allocated obligations.

Risks Related to Our Common Stock

There is not a long market history for our common stock and the market price of our shares may fluctuate widely.

We cannot predict the prices at which our common stock may trade. The market price of our stock may fluctuate widely,,depending upon many factors, some of which are beyond our control, including those described above in "—Risks Related to Our Business" and the following:

- changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- strategic actions by us or our competitors;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- variations in our quarterly operating results and those of our competitors;
- general economic and stock market conditions;
- risks related to our business and our industry, including those discussed above;
- changes in conditions or trends in our industry, markets or customers;

- terrorist acts;
- future sales of our common stock or other securities; and
- investor perceptions of the investment opportunity associated with our common stock relative to other investment alternatives.

These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance. In addition, price volatility may be greater if the public float and trading volume of our common stock is low.

Future issuances of our common stock may depress the price of our common stock.

In the future, we may issue our securities in connection with investments or acquisitions. The amount of shares of our common stock issued in connection with an investment or acquisition could constitute a material portion of our then outstanding shares of our common stock.

We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law ("DGCL"). The future payment of dividends will be at the sole discretion of our Board of Directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our Board of Directors deems relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

Provisions of Delaware law and our charter documents may delay or prevent an acquisition of us that stockholders may consider favorable or may prevent efforts by our stockholders to change our directors or our management, which could decrease the value of your shares.

Section 203 of the DGCL and provisions in our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire us without the consent of our Board of Directors. These provisions include the following:

- restrictions on business combinations for a three-year period with a stockholder who becomes the beneficial owner of more than 15 percent of our common stock;
- restrictions on the ability of our stockholders to remove directors;
- supermajority voting requirements for stockholders to amend our organizational documents; and
- a classified Board of Directors.

Although we believe these provisions protect our stockholders from coercive or otherwise unfair takeover tactics and thereby provide an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our Board of Directors, these provisions apply even if the offer may be considered beneficial by some stockholders. Further, these provisions may discourage potential acquisition proposals and may delay, deter or prevent a change of control of our company, including through unsolicited transactions that some or all of our stockholders might consider to be desirable. As a result, efforts by our stockholders to change our directors or our management may be unsuccessful.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Information regarding our properties is included in Item 1 of this report.

Item 3. ***Legal Proceedings***

See Item 8—Financial Statements and Supplementary Data—Note 11 of our Notes to Consolidated Financial Statements for the information that is called for by this item.

Item 4. ***Mine Safety Disclosures***

Not Applicable

PART II

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

Our common stock began trading on January 3, 2012 and is listed on the New York Stock Exchange under the ticker symbol "WPX". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange:

	Common Stock	
	High	**Low**
Year ended December 31, 2012		
Fourth Quarter	$18.31	$14.43
Third Quarter	$17.73	$14.15
Second Quarter	$18.90	$13.22
First Quarter	$19.74	$14.20

At February 26, 2013, there were 8,725 holders of record of our common stock.

We have not paid or declared any cash dividends on our common stock. Any decision as to future payment of dividends is subject to the discretion of our Board of Directors.

Item 6. *Selected Financial Data*

The following financial data at December 31, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, should be read in conjunction with the other financial information included in Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data* of this Form 10-K. All other financial data has been prepared from our accounting records. The financial statements included in this Form 10-K may not necessarily reflect our financial position, results of operations and cash flows as if we had operated as a stand-alone public company during all periods presented. Accordingly, our results for periods prior to 2012 should not be relied upon as an indicator of our future performance.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(Millions, except per share amounts)				
Statements of operations data:					
Revenues	$3,189	$3,882	$ 3,935	$3,586	$6,047
Income (loss) from continuing operations(a)	$ (233)	$ (150)	$ (937)	$ 182	$ 784
Income (loss) from discontinued operations(b)	22	(142)	(346)	(42)	(56)
Net income (loss)	(211)	(292)	(1,283)	140	728
Less: Net income attributable to noncontrolling interests	12	10	8	6	8
Net income (loss) attributable to WPX Energy	$ (223)	$ (302)	$(1,291)	$ 134	$ 720
Basic and diluted earnings (loss) per common share:					
Income (loss) from continuing operations	$(1.23)	$(0.81)	$ (4.80)	$ 0.89	$ 3.94
Income (loss) from discontinued operations	$ 0.11	$(0.72)	$ (1.75)	$(0.21)	$(0.29)

	As of December 31,				
	2012	2011	2010	2009	2008
	(Millions)				
Balance sheets data					
Notes payable to Williams—current(c)	$ —	$ —	$2,261	$ 1,216	$ 925
Long-term debt	1,508	1,503	—	—	—
Total assets	9,456	10,432	9,846	10,553	11,624
Total equity(c)	5,371	5,759	4,484	5,390	5,493

(a) Income (loss) from continuing operations for the year ended December 31, 2012 includes $225 million of impairment charges related to producing properties and costs of acquired unproved reserves in the Green River Basin, Piceance Basin, and Powder River Basin. Income (loss) from continuing operations for the year ended December 31, 2011 includes $367 million of impairment charges related to producing properties and costs of acquired unproved reserves in the Powder River Basin. Income (loss) from continuing operations for the year ended December 31, 2010 includes a $1 billion impairment charge related to goodwill and a $175 million impairment charge related to costs of acquired unproved reserves in the Piceance Basin. Income (loss) from continuing operations in 2008 includes a $148 million gain related to the sale of a right to an international production payment. See Note 6 of the Notes to Consolidated Financial Statements for further discussion of impairments in 2012, 2011 and 2010.

(b) Income (loss) from discontinued operations includes the results from holdings in the Barnett Shale and Arkoma Basin that were sold in 2012. The activity in 2012, 2011 and 2010 primarily relates to the Barnett Shale and Arkoma Basin operations and the remaining indemnity and other obligations related to the former power business. Activity in 2012 reflects a $38 million gain on the sale of the Barnett Shale and Arkoma Basin. Activity in 2011 and 2010 reflects pre-tax impairment charges of $180 million and $503 million, respectively, related to the Barnett Shale operations. Activity in 2008 reflects a $148 million pre-tax impairment charge related to the producing properties in the Arkoma Basin.

(c) On June 30, 2011, all of our notes payable to Williams were cancelled by Williams. The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in total equity. See Part II, Item 8, *Financial Statements and Supplementary Data* for activity related to our equity at December 31, 2012.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

General

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on exploiting our significant natural gas reserves base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our position in the Bakken Shale oil play in North Dakota and our Marcellus Shale natural gas position in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ("Apco") which holds oil and gas concessions in South America and trades on the NASDAQ Capital Market under the symbol "APAGF".

In conjunction with our exploration and development activities, we engage in natural gas sales and marketing. Our sales and marketing activities includes the sale of our natural gas, oil and NGL production, along with third party purchases and sales of natural gas, which include natural gas purchased from working interest owners in operated wells and other area third party producers. Through May 1, 2012, this activity also included sales of natural gas to Williams Partners L.P. ("Williams Partners") for use in its midstream business. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related price risk management activities. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in product revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

WPX Energy, Inc. was formed in 2011 to effect the separation from The Williams Companies, Inc. ("Williams") of Williams' exploration and production business. On November 30, 2011, Williams' Board of Directors approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011 of WPX common stock to Williams' stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams' stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date.

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes included in Part II, Item 8 in this Form 10-K. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in "Risk Factors" and "Forward-Looking Statements".

Basis of Presentation

The consolidated financial statements for 2011 and 2010 included elsewhere in this Form 10-K, principally represented the Exploration & Production segment of Williams of which the legal entities were contributed to WPX in 2011. Through December 2011, our results included allocations of costs for corporate functions historically provided to us by Williams. See Note 3 of the Notes to Consolidated Financial Statements for more information.

Our management believes the assumptions and methodologies underlying the allocation of expenses from Williams were reasonable. However, such expenses may not be indicative of the actual level of expense that would have been or will be incurred by us as we operate as an independent, publicly traded company.

In second-quarter 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. These properties represented less than five percent of our year- end 2011 proved domestic reserves and approximately five percent of total production in 2011. We have reported the results of operations and financial position of Barnett Shale and Arkoma operations as discontinued operations. Unless otherwise noted, the following discussion relates to our continuing operations.

Overview

The following table presents our production volumes and financial highlights for 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
Production Sales Volume Data:(a)			
Domestic:			
Natural gas (MMcf)	397,483	388,780	371,489
Oil (MBbls)	4,394	2,651	828
NGLs (MBbls)	10,392	10,057	8,054
Domestic combined equivalent volumes (MMcfe)(b)	486,198	465,030	424,780
Domestic combined equivalent volumes (MBoe)	81,033	77,505	70,797
International combined equivalent volumes (MMcfe)(b)(c)	21,218	20,810	19,940
Total WPX combined equivalent volumes (MMcfe)(b)(c)	507,416	485,840	444,720
Production Sales Volume Per Day:			
Domestic:			
Natural Gas (MMcf/d)	1,086	1,065	1,018
Oil (MBbls/d)	12	7	2
NGL (MBbls/d)	28	28	22
Domestic combined equivalent volumes (MMcfe/d)	1,328	1,274	1,163
International combined equivalent volumes (MMcfe/d)(c)	58	57	55
Total WPX per day combined equivalent volumes (MMcfe/d)(c)	1,386	1,331	1,218
Financial Data (millions):			
Total domestic revenues	$ 3,052	$ 3,772	$ 3,846
Total international revenues	$ 137	$ 110	$ 89
Consolidated operating income (loss)	$ (280)	$ (142)	$ (805)
Consolidated capital expenditures	$ 1,521	$ 1,572	$ 1,856

(a) Excludes production from our Barnett Shale and Arkoma Basin operations which are classified as discontinued operations.

(b) Oil and NGLs were converted to MMcfe using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.

(c) Includes approximately 69 percent of Apco's production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

While our total 2012 domestic production volumes increased over 2011, our 2012 results were impacted by lower realized natural gas prices coupled with lower natural gas liquids prices relative to 2011. Also, as a result of declines in forward natural gas prices during 2012 compared to 2011, we recorded impairments of producing properties and costs of acquired unproved reserves totaling $225 million during 2012. Our 2011 results were also impacted by low natural gas prices as compared to 2010 and we recognized impairment charges of $367 million on certain producing properties in 2011. Our 2010 operating results were negatively impacted by a $1 billion full impairment charge related to goodwill and $175 million of pre-tax charges associated with impairments of costs of acquired unproved reserves. See Note 6 of the Notes to the Consolidated Financial Statements.

Outlook

In 2013, we will focus on growing our oil production and developing oil reserves, primarily those located in the Williston Basin. Further, capital will be focused on the development of reserves in the middle Bakken and upper Three Forks formations of this basin.

We will remain disciplined in the development of our natural gas reserves, due to the low natural gas price environment. We will continue to focus our natural gas drilling effort in the NGL rich Piceance basin, because of our scale and efficiency of that operation, together with significant infrastructure already in place. In the Marcellus Shale/Appalachian Basin, we will focus on completing our inventory of drilled locations. Our drilling program in the Marcellus Shale/Appalachian Basin will be limited. Specifically, drilling capital in Susquehanna County, will be minimal due to infrastructure constraints on our third party gatherer's system. Until those constraints have been rectified we will look to develop opportunities in Westmoreland Country in the Appalachian Basin.

We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities and negotiated cost savings on vendor contracts. Additionally, more favorable, previously negotiated gathering and processing contract provisions will become effective in 2013.

We will look to deploy 8 percent to 10 percent of our estimated capital spending on exploratory activities. In 2013, we expect to spud test wells in two new areas as well as continue to look at purchasing land in these and other areas. Our exploration activities are focused on increasing our commodity mix of liquids, primarily oil. We anticipate our capital spending in 2013 will be approximately $1 billion to $1.2 billion.

We continue to operate with a focus on increasing shareholder value and investing in our businesses in a way that enhances our competitive position by:

- Continuing to invest in and grow our production and reserves;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position and liquids-rich basins (primarily Piceance) with high concentrations of NGLs;
- Retaining the flexibility to make adjustments to our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities; and
- Continuing to maintain an active economic hedging program around our commodity price risks.

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

- Lower than anticipated energy commodity prices;
- Higher capital costs of developing our properties;
- Lower than expected levels of cash flow from operations;
- Unavailability of capital;
- Counterparty credit and performance risk;
- Decreased drilling success;
- General economic, financial markets or industry downturn;
- Changes in the political and regulatory environments; and
- Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation.

We anticipate some recovery on natural gas prices in 2013. Should this expected recovery not occur, we would need to either significantly reduce our capital spending or utilize more of our credit facility, or a combination of both. In addition, we expect an improvement in our NGL margins of approximately $25 million to $30 million due to contract provisions that are effective January 1, 2013 associated with previously negotiated gathering and processing agreements in the Piceance Basin.

We continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. For 2013, we have the following contracts as of February 25, 2013 for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

	2013 Natural Gas	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
NYMEX swaps	352	$3.53
Location swaps—Rockies	20	$3.89
Location swaps—San Juan	10	$3.93
Location swaps—Northeast	25	$4.63
Total all swaps	407	$3.62

	2013 Crude Oil	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl) Floor-Ceiling for Collars
WTI crude oil swaps	9,000	$100.52

The following is a summary of our natural gas derivative contracts for daily domestic production shown at daily volumes and basin-level weighted average prices for the years ended December 31, 2012, 2011 and 2010:

	2012		2011		2010	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars	Volume (BBtu/d)	Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars
Collar agreements—Rockies	—	$—	45	$5.30 – $7.10	100	$6.53 – $8.94
Collar agreements—San Juan	—	$—	90	$5.27 – $7.06	233	$5.75 – $7.82
Collar agreements—Mid-Continent	—	$—	80	$5.10 – $7.00	105	$5.37 – $7.41
Collar agreements—Southern California	—	$—	30	$5.83 – $7.56	45	$4.80 – $6.43
Collar agreements—Other	—	$—	30	$6.50 – $8.14	28	$5.63 – $6.87
NYMEX and basis fixed-price swaps	508	$5.06	372	$5.22	120	$4.40

The following is a summary of our crude oil and natural gas liquids contracts for daily domestic production shown at daily volumes and weighted average prices for the years ended December 31, 2012 and 2011:

	2012		2011	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
WTI Crude Oil Swaps	7,503	$ 97.79	3,315	$95.88
WTI Crude Oil costless collar	2,000	$85.00 – 106.30	—	$ —

	2012 Natural Gas Liquids	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Natural Gas Liquids Swaps	3,661	$50.74

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to deliver on a firm basis 200,000 MMbtu/d of natural gas at monthly index pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation, which expires in 2014.

Results of Operations

Operations of our company are located in the United States and South America and are organized into domestic and international reportable segments.

Domestic includes natural gas, natural gas liquids, and oil development and production and gas management activities located in Colorado, New Mexico, North Dakota (Bakken Shale), Pennsylvania (Marcellus Shale), and Wyoming in the United States. Our development and production techniques specialize in production from tight-sands and shale formations as well as coal bed methane reserves in the Piceance, San Juan, Powder River, Green River, Williston (Bakken Shale), and Appalachian (Marcellus Shale) Basins. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related hedges coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco, an oil and gas exploration and production company with concessions primarily in Argentina and Colombia.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. In 2012, we began entering into commodity derivative contracts that continue to serve as economic hedges but are not designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2012 that are included in accumulated other comprehensive income will be realized by the end of the first-quarter 2013.

2012 vs. 2011

Revenue Analysis

	Years ended December 31, 2012	2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$1,346	$1,678	$(332)	(20)%
Oil and condensate sales	376	226	150	66%
Natural gas liquid sales	296	404	(108)	(27)%
Total product revenues	2,018	2,308	(290)	(13)%
Gas management	949	1,428	(479)	(34)%
Net gain (loss) on derivatives not designated as hedges	78	29	49	169%
Other	7	7	—	—%
Total domestic revenues	$3,052	$3,772	$(720)	(19)%
Total international revenues	$ 137	$ 110	$ 27	25%
Total revenues	$3,189	$3,882	$(693)	(18)%

Cost and operating expense and operating income (loss) analysis:

	Years ended December 31, 2012	2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$ 251	$ 235	$ 16	7%
Gathering, processing and transportation	504	487	17	3%
Taxes other than income	87	113	(26)	(23)%
Gas management, including charges for unutilized pipeline capacity	996	1,471	(475)	(32)%
Exploration	72	123	(51)	(41)%
Depreciation, depletion and amortization	939	880	59	7%
Impairment of producing properties and costs of acquired unproved reserves	225	367	(142)	(39)%
General and administrative	273	263	10	4%
Other—net	12	(3)	15	NM
Total domestic costs and expenses	$3,359	$3,936	$(577)	(15)%
International costs and expenses:				
Lease and facility operating	$ 32	$ 27	$ 5	19%
Gathering, processing and transportation	2	—	2	NM
Taxes other than income	24	21	3	14%
Exploration	11	3	8	NM
Depreciation, depletion and amortization	27	22	5	23%
General and administrative	14	12	2	17%
Other—net	—	3	(3)	(100)%
Total international costs and expenses	$ 110	$ 88	$ 22	25%
Total costs and expenses	$3,469	$4,024	$(555)	(14)%
Domestic operating income (loss)	$ (307)	$ (164)	$(143)	87%
International operating income (loss)	$ 27	$ 22	$ 5	23%

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Domestic Costs

Significant variances in comparative costs and expenses reflect:

- Lease and facility operating expense in 2012 averaged $0.52 per Mcfe compared to $0.51 per Mcfe during 2011.
- $17 million increase in gathering, processing and transportation expenses primarily as a result of an increase in natural gas liquids volumes. This increase includes a $9 million adjustment related to royalty calculations for prior periods. Excluding this adjustment, our gathering, processing and transportation charges averaged $1.02 per Mcfe for 2012 compared to an average of $1.05 for 2011.
- $26 million decrease in taxes other than income for 2012 primarily reflecting the impact of decreased total product revenues (excluding hedges) resulting from lower commodity prices in 2012 compared to 2011. Our taxes other than income averaged $0.18 per Mcfe for 2012 compared to an average of $0.24 for 2011.
- $475 million decrease in gas management expenses due to a 27 percent decrease in average prices on physical natural gas cost of sales and a 9 percent decrease in natural gas sales volumes. Also included in

Domestic Revenues

Significant variances in comparative revenues reflect:

- $332 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $3.38 for 2012 compared to $4.32 for 2011 on production sales volumes of 397,483 MMcf and 388,780 MMcf for 2012 and 2011, respectively. Without hedges, our natural gas price per Mcf was $2.32 compared to $3.48 for 2012 and 2011, respectively.
- $150 million increase in oil and condensate sales reflects increased production sales volumes of 4,394 Mbbls in 2012 compared to 2,651 Mbbls in 2011. Price per barrel of oil and condensate was $85.58 (including the impact of hedges) in 2012 compared to $85.30 in 2011.
- $108 million decrease in natural gas liquids sales reflects a per barrel price of $28.56 in 2012 compared to $40.17 in 2011. Production sales volumes were 10,392 Mbbls and 10,057 Mbbls for 2012 and 2011, respectively.
- $479 million decrease in gas management revenues due to a 27 percent decrease in average prices on physical natural gas sales and 9 percent lower natural gas sales volumes. We experienced a similar decrease of $475 million in related gas management costs and expenses.
- $49 million change in net gain (loss) on derivatives not designated as hedges primarily relates to unrealized and realized mark-to-market gains on crude oil and natural gas derivatives not designated as hedges.

International Revenues

International revenues increased primarily due to increased oil sales due to higher average oil sales prices and new oil production in Colombia for 2012 compared to 2011.

gas management expenses are $46 million and $35 million in 2012 and 2011, respectively, for unutilized pipeline capacity. Gas management expenses in 2012 and 2011 also include $11 million and $10 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage.

- $51 million decrease in exploration expenses primarily reflects lower unproved leasehold impairment, amortization and expiration expenses in 2012 compared to 2011 which includes a $50 million write-off impairment of acreage in Columbia County, Pennsylvania that we no longer planned to develop. Additionally, in 2011 we incurred approximately $11 million of dry hole expenses in connection with a Marcellus Shale well in Columbia County because results were inconclusive and raised substantial doubt about the economic and operational viability of the well.
- $59 million increase in depreciation, depletion and amortization expenses which reflects higher production volumes and a slightly higher rate. During 2012 our depreciation, depletion and amortization averaged $1.93 per Mcfe compared to an average $1.89 per Mcfe in 2011. During the course of 2012, we adjusted our estimated proved reserves used for the calculation of depletion and amortization to reflect the impact of the decrease in the 12 month average price; this resulted in a total of approximately $31 million additional depreciation, depletion and amortization expense in 2012 and was the main driver of the increase in the average per Mcfe.
- $225 million of property impairments in 2012 compared to $367 million in 2011, as previously discussed.
- The increase in other-net expense for 2012 primarily reflects $9 million in rig release penalties and rig standby fees. In 2013, we expect to incur additional rig standby fees.

International costs

International costs increased primarily due to higher exploration expenses related to 3-D seismic acquisition costs and dry hole expenses. Costs also increased due to higher depreciation, depletion and amortization and higher production and lifting costs.

Consolidated results below operating income (loss)

	Years ended December 31, 2012	2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Consolidated operating income (loss)	$(280)	$(142)	$(138)	97%
Interest expense	(102)	(117)	15	(13)%
Interest capitalized	8	9	(1)	(11)%
Investment income and other	30	26	4	15%
Loss from continuing operations before income taxes	(344)	(224)	(120)	54%
Benefit for income taxes	(111)	(74)	(37)	50%
Income (loss) from continuing operations	(233)	(150)	(83)	55%
Income (loss) from discontinued operations	22	(142)	164	(115)%
Net income (loss)	(211)	(292)	81	(28)%
Less: Net income attributable to noncontrolling interests	12	10	2	20%
Net income (loss) attributable to WPX Energy	$(223)	$(302)	$ 79	(26)%

Interest expense in 2012 primarily reflects interest accrued on our senior notes issued in November 2011. Interest expense in 2011 primarily reflects interest through June 30, 2011 associated with our unsecured notes payable with Williams. The outstanding amounts were cancelled by Williams and contributed to capital on June 30, 2011. Additionally, interest expense in 2011 also includes $11 million of interest on our senior notes issued in November 2011.

Our investment income and other primarily reflects equity earnings associated with our international and domestic equity method investments.

The benefit for income taxes increased in 2012 from 2011 due to an increased loss from continuing operations. See Note 10 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations reflects a $38 million pretax gain on sale in 2012 and a $209 million pretax impairment in 2011. As previously discussed, we completed the sale of our holdings in Barnett Shale and the Arkoma Basin during 2012. See Note 2 of the Notes to Consolidated Financial Statements.

2011 vs. 2010

Revenue Analysis:

	Years ended December 31, 2011	2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$1,678	$1,700	$ (22)	(1)%
Oil and condensate sales	226	55	171	NM
Natural gas liquid sales	404	282	122	43%
Total product revenues	2,308	2,037	271	13%
Gas management	1,428	1,742	(314)	(18)%
Net gain (loss) on derivatives not designated as hedges	29	27	2	7%
Other	7	40	(33)	(83)%
Total domestic revenues	$3,772	$3,846	$ (74)	(2)%
Total international revenues	$ 110	$ 89	$ 21	24%
Total revenues	$3,882	$3,935	$ (53)	(1)%

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Domestic Revenues

Significant variances in comparative revenues reflect:

- $22 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $4.32 compared to $4.58 in 2010 on production sales volumes of 388,780 MMcf and 371,489 MMcf, respectively. Without hedges, our natural gas price per Mcf in 2011 was $3.48 compared to $3.68 in 2010.
- $171 million increase in oil and condensate sales reflects a per barrel price of $85.30 (including the impact of hedges) in 2011 compared to $65.93 in 2010. Production sales volumes in 2011 were 2,651 Mbbls compared to 828 Mbbls in 2010. Production in 2011 reflected a full year of production associated with producing wells acquired in the Bakken acquisition completed in late 2010 as well as production from wells drilled during 2011.
- $122 million increase in natural gas liquids sales reflects a per barrel price of $40.17 in 2011 compared to $35.02 in 2010. Production sales volumes were 10,057 Mbbls in 2011 versus 8,054 Mbbls in 2010.

- A $314 million decrease in gas management revenues primarily due to a 7 percent decrease in average prices on physical natural gas sales and 12 percent lower natural gas sales volumes. We experienced a similar decrease of $296 million in related gas management costs and expenses.
- A $33 million decrease in other revenues primarily related to the absence of gathering revenues associated with the gathering and processing assets in Colorado's Piceance Basin that were sold to Williams Partners in the fourth quarter of 2010.

International Revenues

International revenues increased primarily due to increased average oil sales prices.

Cost and operating expense and operating income (loss) analysis:

	Years ended December 31, 2011	Years ended December 31, 2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$ 235	$ 244	$ (9)	(4)%
Gathering, processing and transportation	487	320	167	52%
Taxes other than income	113	104	9	9%
Gas management, including charges for unutilized pipeline capacity	1,471	1,767	(296)	(17)%
Exploration	123	51	72	141%
Depreciation, depletion and amortization	880	794	86	11%
Impairment of producing properties and costs of acquired unproved reserves	367	175	192	110%
Goodwill Impairment	—	1,003	(1,003)	NM
General and administrative	263	233	30	13%
Other—net	(3)	(18)	15	(83)%
Total domestic costs and expenses	$3,936	$4,673	(737)	(16)%
International costs and expenses:				
Lease and facility operating	$ 27	$ 19	8	42%
Taxes other than income	21	16	5	31%
Exploration	3	6	(3)	(50)%
Depreciation, depletion and amortization	22	17	5	29%
General and administrative	12	9	3	33%
Other—net	3	—	3	NM
Total international costs and expenses	$ 88	$ 67	$ 21	31%
Total costs and expenses	$4,024	$4,740	$ (716)	(15)%
Domestic operating income (loss)	$ (164)	$ (827)	$ 663	(80)%
International operating income (loss)	$ 22	$ 22	$ —	— %

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Domestic Costs

Significant variances in comparative costs and expenses reflect:

- Lease and facility operating expense reflects higher costs associated with higher production and increased workover, water management, and maintenance activity, offset by the absence in 2011 of $28 million in expenses associated with the previously owned gathering and processing assets. Lease and facility operating expense in 2011 averaged $0.51 per Mcfe compared to $0.57 per Mcfe during 2010. Excluding the $28 million of expenses associated with the previously owned gathering and processing assets, lease obligation expense in 2010 averaged $0.51 per Mcfe.
- $167 million higher gathering, processing and transportation expenses primarily as a result of fees paid to Williams Partners in 2011 for gathering and processing associated with certain gathering and processing assets in the Piceance Basin that we sold to Williams Partners in the fourth quarter of 2010 and an increase in natural gas liquids volumes processed at Williams Partners' Willow Creek plant. During 2011, gathering, processing and transportation expenses were $132 million higher due to fees paid to Williams Partners pursuant to the gathering and processing agreement associated with the assets sold Williams Partners in the fourth quarter of 2010. During 2010, our operating costs were $58 million associated with these assets (primarily reflected in lease and facility operating costs ($28 million) and depreciation, depletion and amortization ($17 million)). These costs are no longer directly incurred as operating costs (but rather as gathering, processing and transportation expenses) as we no longer own or operate these assets. Our gathering, processing and transportation charges averaged $1.05 per Mcfe in 2011 compared to an average of $0.75 per Mcfe in 2010.
- $9 million increase in taxes other than income primarily associated with higher oil and natural gas liquids sales volumes.
- $296 million decrease in gas management expenses, primarily due to a 6 percent decrease in average prices on physical natural gas cost of sales and a 12 percent decrease in natural gas sales volumes. This activity represents natural gas purchased in connection with our gas purchase activities for Williams Partners and certain working interest owners' share of production and to manage our transportation and storage activities. The sales associated with our marketing of this gas are included in gas management revenues. Also included in gas management expenses are $35 million and $44 million in 2011 and 2010, respectively, for unutilized pipeline capacity. Gas management expenses in 2011 and 2010 also include $10 million and $2 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage.
- $72 million increase in exploration expense primarily due to the previously discussed dry hole and leasehold write-offs of $61 million in Columbia County, Pennsylvania coupled with increased leasehold amortization costs associated with leasehold acquisitions. Partially off-setting these increases is the absence of $15 million in dry hole charges recognized in 2010 associated with the Paradox Basin.
- $86 million increase in depreciation, depletion and amortization expenses which reflects higher production volumes partially offset by the absence of $17 million of depreciation expense related to the assets sold to Williams Partners in 2010. During 2011, our depreciation, depletion and amortization averaged $1.89 per Mcfe compared to an average $1.87 per Mcfe in 2010.
- $367 million of property impairments in 2011 compared to $175 million in 2010.
- The absence of the goodwill impairment from 2010 to 2011, as previously discussed.
- $30 million increase in general and administrative expenses primarily due to higher wages, salary and benefits costs primarily as a result of an increase in the number of employees. Our general and administrative expenses in 2011 averaged $0.57 per Mcfe in 2011 compared to an average of $0.55 per Mcfe in 2010. Additionally, general and administrative expenses in 2011 reflect approximately $5 million in costs associated with our initial public offering efforts and approximately $5 million in stock based compensation expense.

- Other-net in 2010 reflects a gain on sale of $12 million associated with a sale of a portion of gathering and processing assets in the Piceance Basin and a $7 million gain on the exchange of undeveloped leasehold acreage with a third party.

International Costs

International costs increased primarily due to increased production and lifting costs due to greater operating and maintenance activity and increased operating taxes associated with increased revenues.

Consolidated results below operating income (loss)

	Years ended December 31, 2011	Years ended December 31, 2010	$ Change	Percentage Increase (Decrease)
	(Millions)			
Consolidated operating income (loss)	$(142)	$ (805)	$663	(82)%
Interest expense	(117)	(124)	7	(6)%
Interest capitalized	9	15	(6)	(40)%
Investment income and other	26	21	5	24%
Income (loss) from continuing operations before income taxes	(224)	(893)	669	(75)%
Provision (benefit) for income taxes	(74)	44	118	NM
Income (loss) from continuing operations	(150)	(937)	787	(84)%
Income (loss) from discontinued operations	(142)	(346)	204	(59)%
Net income (loss)	(292)	(1,283)	991	(77)%
Less: Net income attributable to noncontrolling interests	10	8	2	25%
Net income (loss) attributable to WPX Energy	$(302)	$(1,291)	$989	(77)%

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Interest expense in 2011 primarily reflects interest expense to Williams for six months as Williams cancelled and contributed to capital all amounts due under our unsecured notes payable with them on June 30, 2011. Also, 2011 reflects interest expense on our senior notes issued in November 2011. All cash receipts and cash expenditures transferred to or from Williams from July 1, 2011 to November 30, 2011 were considered owner's equity transactions between us and Williams and therefore no interest expense was recorded during this period. Interest expense in 2010 primarily reflects interest paid to Williams on outstanding notes payable to Williams.

Our investment income and other primarily reflects from equity earnings associated with our international and domestic equity method investments.

Provision (benefit) for income taxes in 2010 reflects the nondeductibility of goodwill impairment for tax purposes. See Note 10 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

In 2012, we continued to focus upon growth through continued disciplined investments in expanding our natural gas, oil and NGL portfolio while completing the separation from Williams.

Our main sources of liquidity are cash on hand, internally generated cash flow from operations and our bank credit facility. Additional sources of liquidity, if needed and if available, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. Prior to December 1, 2011, our liquidity was managed through an internal cash management program with Williams. Daily cash activity from our domestic operation was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011, at which time the notes were cancelled by Williams. Any cash activity from July 1, 2011 until November 30, 2011 was treated as capital contribution. On December 1, 2011, we began to manage our own cash beginning with the $500 million retained after the issuance of the senior notes. In consideration of our liquidity, we note the following:

- As of December 31, 2012, we maintained liquidity through cash, cash equivalents and available credit capacity under our credit facility.
- Our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support.
- Apco's liquidity requirements have historically been provided by its cash flows from operations and cash on hand. Included in our cash and cash equivalents at December 31, 2012 is $35 million related to our international operations.

Outlook

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures, and tax and debt payments while maintaining a sufficient level of liquidity. Our primary sources of liquidity in 2013 are expected cash flows from operations and borrowings on our $1.5 billion credit facility. The combination of these sources should be sufficient to allow us to pursue our business strategy and goals for 2013.

We note the following assumptions for 2013:

- Our capital expenditures, including international, are estimated to be approximately $1 billion to $1.2 billion in 2013, and are generally considered to be largely discretionary; and
- Apco's liquidity requirements will continue to be provided from its cash flows from operations and cash on hand.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;
- Higher than expected collateral obligations that may be required, including those required under new commercial agreements;
- Significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold; and
- Reduced access to our credit facility

Under the credit facility agreement ("Credit Facility Agreement") and prior to our receipt of an investment grade rating with a stable outlook, we are required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. Net present value is determined as of the end of each fiscal year and reflects the present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves (such cash flows are adjusted to reflect the impact of hedges, our lenders' commodity price forecasts, and, if necessary,to include only a portion of our reserves that are not proved developed producing reserves). Further declines in natural gas prices during future years could reduce our net present value and thus limit our available capacity under the agreement. However, we believe that we have full access to the $1.5 billion in 2013 based on year-end pricing. See Note 9 of the Notes to Consolidated Financial Statements.

We have executed three bilateral, uncommitted letter of credit agreements which we anticipate will be renewed annually. These agreements allow us to preserve our liquidity under our revolving credit agreement while providing support to our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility Agreement. At December 31, 2012 a total of $312 million in letters of credit have been issued.

Credit Ratings

Our ability to borrow money will be impacted by several factors, including our credit ratings. Credit ratings agencies perform independent analysis when assigning credit ratings. A downgrade of our current rating could increase our future cost of borrowing and result in a requirement that we post additional collateral with third parties, thereby negatively affecting our available liquidity. The current ratings are as follows:

Standard and Poor's(a)	
Corporate Credit Rating	BB+
Senior Unsecured Debt Rating	BB+
Outlook	Stable
Moody's Investors Service(b)	
Senior Unsecured Debt Rating	Ba1
LT Corporate Family Rating	Ba1
Outlook	Stable

(a) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

(b) A rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. The "1," "2," and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" indicates the lower end of the category.

Sources (Uses) of Cash

The following table and discussion summarize our sources (uses) of cash for the years ended December 31, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 794	$ 1,206	$ 1,056
Investing activities	(1,204)	(1,556)	(2,337)
Financing activities	37	839	1,284
Increase (decrease) in cash and cash equivalents	$ (373)	$ 489	$ 3

Operating activities

Our net cash provided by operating activities in 2012 decreased from 2011 primarily due to lower realized commodity prices.

The increase in net cash provided by operating activities in 2011 from 2010 is primarily due to net favorable changes in our operating assets and liabilities compared to 2010.

Investing activities

Our net cash used by investing activities in 2012 decreased from 2011 primarily due to the proceeds from the sale of our holdings in the Barnett Shale and Arkoma Basin. Our net cash used by investing activities in 2011 decreased from 2010 primarily due to reduced capital expenditures and the absence of our acquisitions in 2010 for Marcellus Shale and Bakken Shale properties.

Significant items include:

2012

- Expenditures for drilling and completion were approximately $1.2 billion.
- Proceeds of $306 million from the sale of our holdings in the Barnett Shale and Arkoma Basin.

2011

- Expenditures for drilling and completion were approximately $1.4 billion.

2010

- Expenditures for drilling and completion were approximately $950 million.
- Our acquisition in July 2010 of properties in the Marcellus Shale for $599 million.
- Our acquisition in December 2010 of oil and gas properties in the Bakken Shale for $949 million.
- The sale in November 2010 of certain gathering and processing assets in the Piceance Basin to Williams Partners for $702 million in cash ($244 million of which was in excess of our net book value and thus a financing and capital transaction with Williams) and approximately 1.8 million Williams Partners common units, which were subsequently distributed to Williams.

Financing activities

Net cash provided by financing activities in 2012 includes $10 million of a contribution from a third party related to the formation of a consolidated limited liability company. This company was formed to hold gathering facilities.

Our net cash provided by financing activities decreased in 2011 compared to 2010 primarily due to distribution to Williams of approximately $981 million from our $1.5 billion in Note proceeds in November 2011 offset by lower borrowings from Williams in 2011 compared to 2010.

Off-Balance Sheet Financing Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at December 31, 2012 and December 31, 2011.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2012.

	2013	2014 – 2015	2016 – 2017	Thereafter	Total
			(Millions)		
Long-term debt, including current portion					
Principal	$ 1	$ 7	$ 402	$1,100	$ 1,510
Interest	87	174	164	297	722
Operating leases and associated service commitments					
Drilling rig commitments(a)	125	149	2	—	276
Other	16	19	17	29	81
Transportation and storage commitments(b)	205	418	367	741	1,731
Natural gas purchase commitments(c)	124	304	275	523	1,226
Oil and gas activities(d)	219	207	146	158	730
Other	15	22	4	—	41
Other long-term liabilities, including current portion:					
Physical and financial derivatives(e)	297	593	643	2,315	3,848
Total	$1,089	$1,893	$2,020	$5,163	$10,165

(a) Includes materials and services obligations associated with our drilling rig contracts.

(b) Excludes additional commitments totaling $87 million associated with projects for which the counterparty has not yet received satisfactory regulatory approvals.

(c) Purchase commitments are at market prices and the purchased natural gas can be sold at market prices. The obligations are based on market information as of December 31, 2012 and contracts are assumed to remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur. Certain parties have elected to convert their gas purchase agreements to firm gathering and processing agreements, which services will be provided by Williams Partners. WPX Energy's gas purchase obligations totaling $1.2 billion will terminate at the effective date of the new agreements.

(d) Includes gathering, processing and other oil and gas related services commitments. Excluded are liabilities associated with asset retirement obligations, which total $321 million as of December 31, 2012. The ultimate settlement and timing cannot be precisely determined in advance; however, we estimate that approximately 9 percent of this liability will be settled in the next five years.

(e) Includes $3.8 billion of physical natural gas derivatives related to purchases at market prices. The natural gas expected to be purchased under these contracts can be sold at market prices, largely offsetting this obligation. The obligations for physical and financial derivatives are based on market information as of December 31, 2012, and assume contracts remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur.

Effects of Inflation

Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy. Operating costs are influenced by both competition for specialized services and specific price changes in natural gas, oil, NGLs and other commodities. We tend to experience inflationary pressure on the cost of services and equipment as increasing oil and gas prices increase drilling activity in our areas of operation.

Environmental

Our operations are subject to governmental laws and regulations relating to the protection of the environment, and increasingly strict laws, regulations and enforcement policies, as well as future additional environmental requirements, could materially increase our costs of operation, compliance and any remediation that may become necessary.

Critical Accounting Estimates

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

In our management's opinion, the more significant reporting areas impacted by management's judgments and estimates are as follows:

Impairments of Long-Lived Assets

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset, and the current and future economic environment in which the asset is operated.

Due to the drop in natural gas and natural gas liquids forward prices during 2012, we assessed our natural gas producing properties and acquired unproved reserve costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of reserves quantities, estimates of future commodity prices (primarily natural gas, using a forward NYMEX curve adjusted for locational basis differentials) drilling plans, expected capital costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The assessment performed identified certain properties with a carrying value in excess of those undiscounted cash flows and their calculated fair values. As a result, we recognized $225 million of impairment charges in 2012. See Notes 6 and 15 of the Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately three percent could be at risk for impairment if forward prices across all future periods decline by approximately 11 percent to 12 percent, on average, as compared to the forward commodity prices at December 31, 2012. We estimate that approximately 31 percent could be at risk for impairment if forward commodity prices across all periods decline by approximately 16 percent to 18 percent. A substantial portion of the remaining carrying value of these other assets could be at risk for impairment if forward commodity prices across all future periods decline by approximately 23 percent, on average, as compared to the prices at December 31, 2012.

Accounting for Derivative Instruments and Hedging Activities

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, new commodity derivative contracts that serve as economic hedges of production will not be designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2012 that are included in accumulated other comprehensive income will be realized by the end of the first-quarter 2013.

We review our energy contracts to determine whether they are, or contain, derivatives. Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short-term, with more than 99 percent of the value of our derivatives portfolio expiring in the next 24 months. We further assess the appropriate accounting method for any derivatives identified, which could include:

- applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings;
- qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or
- qualifying for and electing cash flow hedge accounting, which recognizes changes in the fair value of the derivative in other comprehensive income (to the extent the hedge is effective) until the hedged item is recognized in earnings for derivatives entered into prior to 2012.

If cash flow hedge accounting or accrual accounting is not applied, a derivative is subject to mark-to-market accounting. Determination of the accounting method involves significant judgments and assumptions, which are further described below.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in offsetting the cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives designated as cash flow hedges, we must periodically assess whether they continue to qualify for hedge accounting. We prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclassify amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting the cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

Since our energy derivative contracts could be accounted for in three different ways, two of which are elective, our accounting method could be different from that used by another party for a similar transaction. Furthermore, the accounting method may influence the level of volatility in the financial statements associated with changes in the fair value of derivatives, as generally depicted below:

	Consolidated Statements of Operations		Consolidated Balance Sheets	
Accounting Method	**Drivers**	**Impact**	**Drivers**	**Impact**
Accrual Accounting	Realizations	Less Volatility	None	No Impact
Cash Flow Hedge Accounting	Realizations & Ineffectiveness	Less Volatility	Fair Value Changes	More Volatility
Mark-to-Market Accounting	Fair Value Changes	More Volatility	Fair Value Changes	More Volatility

Our determination of the accounting method does not impact our cash flows related to derivatives.

Additional discussion of the accounting for energy contracts at fair value is included in Notes 1 and 16 of Notes to Consolidated Financial Statements.

Successful Efforts Method of Accounting for Oil and Gas Exploration and Production Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates; and
- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, over 99 percent of our domestic reserves estimates are audited by independent experts. The data may change substantially over time as a result of numerous factors, including additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserves estimates could occur from time to time. Such changes could trigger an impairment of our oil and gas properties and have an impact on our depreciation, depletion and amortization expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual depreciation, depletion and amortization expense between approximately $83 million and $102 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserves categories.

Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the forward price curve could result in an impairment of our oil and gas properties.

We record the cost of leasehold acquisitions as incurred. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. Changes in our assumptions regarding the estimates of the nonproductive portion of these leasehold acquisitions could result in impairment of these costs. Upon determination that specific acreage will not be developed, the costs associated with that acreage would be impaired. Our capitalized lease acquisition costs, including costs of acquired unproved reserves, totaled $1.1 billion at December 31, 2012.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including royalty litigation, environmental and other contingent matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 11 of the Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Liabilities

We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years. Included in our deferred taxes are deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of book basis, from certain separate state losses generated in the current and prior years and, effective with the spin-off, from certain tax attributes allocated between us and Williams. We must periodically evaluate whether it is more likely than not we will realize these deferred tax assets and establish a valuation allowance for those that do not meet the more likely than not threshold. When assessing the need for a valuation allowance, we consider future reversals of existing taxable temporary differences, future taxable income exclusive of reversing temporary differences and carryforwards, and tax-planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryforwards. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

The determination of our state deferred tax requires judgment as we did not exist as a stand-alone filer in all states prior to the spin-off and the state deferred tax can change periodically based on changes in our operations. Our state deferred tax is based upon our current entity structure and the jurisdictions in which we operate.

See Note 10 of the Notes to Consolidated Financial Statements for additional information.

Fair Value Measurements

A limited amount of our energy derivative assets and liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities, we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2012, the credit reserve is less than $1 million on our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2012, 98 percent of the fair value of our derivatives portfolio expires in the next 12 months and approximately 100 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2012, consist of natural gas index transactions that are used to manage the physical requirements of our business. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices during the month of delivery. There are generally no active forward markets or quoted prices for natural gas index transactions.

For the years ended December 31, 2012 and 2011, we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. See Note 15 of the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is related primarily to our debt portfolio. Our Notes are fixed rate debt in order to mitigate the impact of fluctuations in interest rates and we expect that any borrowings under our credit facility will most likely be at a variable interest rate and could expose us to the risk of increasing interest rates. For our fixed rate debt, $400 million matures in 2017 and $1,100 million matures in 2022. Interest rates for each group are 5.25 percent and 6.00 percent, respectively. The aggregate fair value of the Notes is $1,609 million. See Note 9 of the Notes to the Consolidated Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, NGLs and crude oil, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Note 15 and 16 of the Notes to Consolidated Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of $1 million at December 31, 2012 and a net liability of $4 million at December 31, 2011. The value at risk for contracts held for trading purposes was less than $1 million at December 31, 2012, December 31, 2011 and December 31, 2010.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $39 million and $14 million at December 31, 2012 and December 31, 2011, respectively.

The value at risk for derivative contracts held for nontrading purposes was $6 million at December 31, 2012, and $15 million at December 31, 2011. During the year ended December 31, 2012, our value at risk for these contracts ranged from a high of $27 million to a low of $6 million. The decrease in value at risk from December 31, 2011 primarily reflects the realization of derivative positions partially offset by new derivative contracts.

Item 8. ***Financial Statements and Supplementary Data***

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2012, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on our assessment, we concluded that, as of December 31, 2012, our internal control over financial reporting was effective.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

The Board of Directors and Shareholders of WPX Energy, Inc.

We have audited WPX Energy, Inc. internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). WPX Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, WPX Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of WPX Energy, Inc. as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2012, of WPX Energy, Inc. and our report dated February 28, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 28, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of WPX Energy, Inc.

We have audited the accompanying consolidated balance sheets of WPX Energy, Inc. as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15.(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of WPX Energy, Inc. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), WPX Energy, Inc.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 28, 2013

WPX Energy, Inc.

Consolidated Balance Sheets

	December 31, 2012	December 31, 2011
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$ 153	$ 526
Accounts receivable, net of allowance of $11 and $13 as of December 31, 2012 and 2011, respectively	443	509
Deferred income taxes	17	—
Derivative assets	58	506
Inventories	66	73
Other	35	60
Total current assets	772	1,674
Investments	145	125
Properties and equipment, net (successful efforts method of accounting)	8,416	8,222
Derivative assets	2	10
Other noncurrent assets	121	401
Total assets	$9,456	$10,432
Liabilities and Equity		
Current liabilities:		
Accounts payable	509	702
Accrued and other current liabilities	203	186
Deferred income taxes	—	116
Derivative liabilities	14	152
Total current liabilities	726	1,156
Deferred income taxes	1,401	1,556
Long-term debt	1,508	1,503
Derivative liabilities	1	7
Asset retirement obligations	316	283
Other noncurrent liabilities	133	168
Contingent liabilities and commitments (Note 11)		
Equity:		
Stockholders' equity:		
Preferred stock (100 million shares authorized at $0.01 par value; no shares issued)	—	—
Common stock (2 billion shares authorized at $0.01 par value; 199.3 million shares issued at December 31, 2012 and 197.1 million shares issued at December 31, 2011)	2	2
Additional paid-in-capital	5,487	5,457
Accumulated deficit	(223)	—
Accumulated other comprehensive income	2	219
Total stockholders' equity	5,268	5,678
Noncontrolling interests in consolidated subsidiaries	103	81
Total equity	5,371	5,759
Total liabilities and equity	$9,456	$10,432

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Operations

	Years Ended December 31,		
	2012	2011	2010
	(Millions, except per share amounts)		
Revenues:			
Product revenues:			
Natural gas sales	$1,364	$1,694	$ 1,715
Oil and condensate sales	491	312	126
Natural gas liquid sales	299	408	285
Total product revenues	2,154	2,414	2,126
Gas management	949	1,428	1,742
Net gain (loss) on derivatives not designated as hedges (Note 16)	78	29	27
Other	8	11	40
Total revenues	3,189	3,882	3,935
Costs and expenses:			
Lease and facility operating	283	262	263
Gathering, processing and transportation	506	487	320
Taxes other than income	111	134	120
Gas management, including charges for unutilized pipeline capacity	996	1,471	1,767
Exploration	83	126	57
Depreciation, depletion and amortization	966	902	811
Impairment of producing properties and costs of acquired unproved reserves (Note 6)	225	367	175
Goodwill impairment	—	—	1,003
General and administrative	287	275	242
Other—net	12	—	(18)
Total costs and expenses	3,469	4,024	4,740
Operating income (loss)	(280)	(142)	(805)
Interest expense	(102)	(117)	(124)
Interest capitalized	8	9	15
Investment income and other	30	26	21
Income (loss) from continuing operations before income taxes	(344)	(224)	(893)
Provision (benefit) for income taxes	(111)	(74)	44
Income (loss) from continuing operations	(233)	(150)	(937)
Income (loss) from discontinued operations	22	(142)	(346)
Net income (loss)	(211)	(292)	(1,283)
Less: Net income attributable to noncontrolling interests	12	10	8
Net income (loss) attributable to WPX Energy	$ (223)	$ (302)	$(1,291)
Amounts attributable to WPX Energy, Inc.:			
Basic and diluted earnings (loss) per common share (Note 5):			
Income (loss) from continuing operations	$ (1.23)	$ (0.81)	$ (4.80)
Income (loss) from discontinued operations	0.11	(0.72)	(1.75)
Net income (loss)	$ (1.12)	$ (1.53)	$ (6.55)
Weighted-average shares	198.8	197.1	197.1

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Net income (loss) attributable to WPX Energy	$(223)	$(302)	$(1,291)
Other comprehensive income (loss):			
Change in fair value of cash flow hedges, net of tax(a)	$ 57	$ 262	$ 321
Net reclassifications into earnings of net cash flow hedge gains, net of tax(b)	(274)	(211)	(225)
Other comprehensive income (loss), net of tax	(217)	51	96
Comprehensive income (loss) attributable to WPX Energy	$(440)	$(251)	$(1,195)

(a) Change in fair value of cash flow hedges are net of $33 million, $151 million and $184 million of income tax for 2012, 2011 and 2010, respectively.

(b) Net reclassifications into earnings of net cash flow hedge gains are net of $159 million, $120 million and $129 million of income tax for 2012, 2011 and 2010, respectively.

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Changes in Equity

	WPX Energy, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Williams' Net Investment	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests(a)	Total
	(Dollars in millions)							
Balance at December 31, 2009	$—	$ —		$ 5,254	$ 72	$ 5,326	$ 64	$ 5,390
Comprehensive income:								
Net income (loss)	—	—		(1,291)	—	(1,291)	8	(1,283)
Other comprehensive income (loss)	—	—		—	96	96	—	96
Comprehensive income (loss)								(1,187)
Cash proceeds in excess of historical book value related to assets sold to a Williams' affiliate	—	—		244	—	244	—	244
Net transfers with Williams	—	—		37	—	37	—	37
Dividends to noncontrolling interests	—	—		—	—	—	—	—
Balance at December 31, 2010	—	—		4,244	168	4,412	72	4,484
Comprehensive income:								
Net income (loss)	—	—		(302)	—	(302)	10	(292)
Other comprehensive income (loss)	—	—		—	51	51	—	51
Comprehensive income (loss)								(241)
Contribution of Notes Payable to Williams (Note 3)	—	—		2,420	—	2,420	—	2,420
Allocation of alternative minimum tax credit (Note 10)	—	—		98	—	98	—	98
Net transfers with Williams				(25)	—	(25)	—	(25)
Distribution to Williams a portion of note proceeds	—	—		(981)	—	(981)	—	(981)
Recapitalization upon contribution by Williams	2	5,452		(5,454)	—	—	—	—
Dividends to noncontrolling interests	—	—		—	—	—	(1)	(1)
Stock based compensation, net of tax benefit	—	5		—	—	5	—	5
Balance at December 31, 2011	2	5,457		—	219	5,678	81	5,759
Comprehensive income:								
Net income (loss)	—	—	(223)			(223)	12	(211)
Other comprehensive income (loss)	—	—			(217)	(217)		(217)
Comprehensive loss								(428)
Contribution from noncontrolling interest	—	—		—	—	—	10	10
Stock based compensation, net of tax benefit	—	30		—	—	30	—	30
Balance at December 31, 2012	$ 2	$5,487	$(223)	$ —	$ 2	$ 5,268	$103	$ 5,371

(a) Primarily represents the 31 percent of Apco Oil and Gas International Inc. owned by others.

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Cash Flows

	2012	2011	2010
	Years Ended December 31, (Millions)		
Operating Activities			
Net income (loss)	$ (211)	$ (292)	$(1,283)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	973	951	882
Deferred income tax benefit	(160)	(176)	(166)
Provision for impairment of goodwill and properties and equipment (including certain exploration expenses)	288	694	1,734
Amortization of stock-based awards	28	5	—
(Gain) loss on sales of other assets	(42)	(1)	(22)
Cash provided (used) by operating assets and liabilities:			
Accounts receivable	68	(100)	28
Inventories	7	3	(16)
Margin deposits and customer margin deposit payable	(5)	(18)	(1)
Other current assets	7	(11)	19
Accounts payable	(128)	131	(54)
Accrued and other current liabilities	12	10	(62)
Changes in current and noncurrent derivative assets and liabilities	(32)	8	(45)
Other, including changes in other noncurrent assets and liabilities	(11)	2	42
Net cash provided by operating activities	794	1,206	1,056
Investing Activities			
Capital expenditures(a)	(1,521)	(1,572)	(1,856)
Purchase of business	—	—	(949)
Proceeds from sales of assets	310	15	493
Purchases of investments	(2)	(12)	(7)
Other	9	13	(18)
Net cash used in investing activities	(1,204)	(1,556)	(2,337)
Financing Activities			
Proceeds from common stock	3	—	—
Proceeds from long term debt	6	1,502	—
Proceeds from revolver debt	50	—	—
Payments of revolver debt	(50)	—	—
Contribution from noncontrolling interest	10	—	—
Excess tax benefit of stock based awards	13	—	—
Payments for debt issuance costs	—	(30)	—
Net increase in notes payable to Williams	—	159	1,045
Net changes in Williams' net investment, including a $981 distribution in 2011	—	(777)	241
Other	5	(15)	(2)
Net cash provided by financing activities	37	839	1,284
Net increase (decrease) in cash and cash equivalents	(373)	489	3
Cash and cash equivalents at beginning of period	526	37	34
Cash and cash equivalents at end of period	$ 153	$ 526	$ 37

	2012	2011	2010
(a) Increase to properties and equipment	$(1,449)	$(1,641)	$(1,891)
Changes in related accounts payable	(72)	69	35
Capital expenditures	$(1,521)	$(1,572)	$(1,856)

See accompanying notes.

WPX Energy, Inc.
Notes to Consolidated Financial Statements

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company are located in the United States and South America and are organized into domestic and international reportable segments.

Domestic includes natural gas, oil, and NGL development and production and gas management activities located in Colorado, New Mexico, North Dakota (Bakken Shale), Pennsylvania (Marcellus Shale), and Wyoming in the United States. We specialize in development and production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Williston (Bakken Shale), Green River, and Appalachian (Marcellus Shale) Basins. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related derivatives coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco Oil and Gas International Inc. ("Apco", NASDAQ listed: APAGF), an oil and gas exploration and production company with concessions in Argentina and Colombia.

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as "WPX" or the "Company", comprised substantially all of the exploration and production reportable segment of The Williams Companies, Inc. prior to 2012. In these notes, WPX Energy, Inc. is at times referred to in the first person as "WPX", "we", "us" or "our". The Williams Companies, Inc. and its affiliates, including Williams Partners L.P. ("Williams Partners") are at times referred to collectively as "Williams".

On February 16, 2011, Williams announced that its Board of Directors had approved pursuing a plan to separate Williams' businesses into two stand-alone, publicly traded companies. As a result, WPX Energy, Inc. was formed to effect the separation. In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business, including its wholly-owned subsidiaries WPX Energy Holdings, LLC (formerly Williams Production Holdings, LLC) and WPX Energy Production, LLC (formerly Williams Production Company, LLC), as well as all ongoing operations of WPX Energy Marketing, LLC (formerly Williams Gas Marketing, Inc.). Additionally, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its 69 percent ownership interest in Apco in October 2011. We refer to the collective contributions described herein as the "Contribution".

On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011 of WPX common stock to Williams' stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams' stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date. See Note 3 for further discussion of agreements entered at the time of the spin-off, including a separation and distribution agreement, a transition services agreement, an employee matters agreement and a tax sharing agreement, among others.

Basis of Presentation

These financial statements are prepared on a consolidated basis. Prior to the Contribution, the financial statements were derived from the financial statements and accounting records of Williams using the historical results of operations and historical basis of the assets and liabilities of the Contribution to WPX.

Management believes the assumptions underlying the financial statements are reasonable. However, the financial statements included herein may not necessarily reflect the Company's results of operations, financial position and cash flows in the future or what its results of operations, financial position and cash flows would have been had the Company been a stand-alone company during 2011 and 2010. Because a direct ownership relationship did not exist prior to the Contribution among the various entities that comprise the Company, Williams' net investment in the Company, excluding notes payable to Williams, has been shown as Williams' net investment within stockholder's equity in the consolidated financial statements. In connection with the Contribution, we have reflected the amounts previously presented as Williams' net investment in excess of the par value of our common stock as additional paid-in capital. Transactions in 2011 and 2010 with Williams' other operating businesses, which generally settled monthly, are shown as accounts receivable or accounts payable for December 31, 2011 (see Note 3). Other transactions during the period prior to separation between the Company and Williams which were not part of the notes payable to Williams have been identified in the Consolidated Statements of Equity as net transfers with Williams (see Note 3).

Discontinued operations

During the second quarter of 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. We have reported the results of operations and financial position of Barnett Shale and Arkoma operations as discontinued operations for all periods presented.

Additionally, the accompanying consolidated financial statements and notes include the results of operations of Williams' former power business (most of which was disposed in 2007) as discontinued operations. See Note 11 for a discussion of contingencies related to this discontinued power business.

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

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our wholly and majority-owned subsidiaries and investments. Companies in which we own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the company, are accounted for under the equity method. All material intercompany transactions have been eliminated.

Use of estimates

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

Significant estimates and assumptions which impact these financials include:

- Impairment assessments of long-lived assets and goodwill;
- Valuations of derivatives;
- Hedge accounting correlations and probability;
- Estimation of oil and natural gas reserves; and
- Assessments of litigation-related contingencies.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Our cash and cash equivalents balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Restricted cash

Restricted cash of our domestic operations primarily consists of approximately $19 million in both 2012 and 2011 related to escrow accounts established as part of the settlement agreement with certain California utilities and is included in other noncurrent assets. Included in the separation and distribution agreement with Williams are indemnifications requiring us to pay to Williams any net asset (or receive any net liability) that result upon ultimate resolution of these matters (see Note 11). Additionally, our international segment holds approximately $9 million of restricted cash in 2012 associated with various letters of credit that is also classified in other current and other noncurrent assets.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. A portion of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Inventories

All inventories are stated at the lower of cost or market. Our inventories consist of tubular goods and production equipment for future transfer to wells of $42 million in 2012 and $39 million in 2011. Additionally, we have natural gas in storage of $24 million in 2012 and $34 million in 2011 primarily related to our gas management activities. Inventory is recorded and relieved using the weighted average cost method except for production equipment which is on the specific identification method. We recognized lower of cost or market writedowns on natural gas in storage of $11 million in 2012, $10 million in 2011 and $2 million in 2010.

Properties and equipment

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to exploration expense. Other exploration costs, including geological and geophysical costs and lease rentals are charged to expense as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred whether productive or nonproductive.

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of lease acquisition costs are included in exploration expense in the Consolidated Statements of Operations. A majority of the costs of acquired unproved reserves are associated with areas to which we or other producers have identified significant proved developed producing reserves. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of unproved reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. We refer to unproved lease acquisition costs and costs of acquired unproved reserves as unproved properties.

Other capitalized costs

Costs related to the construction or acquisition of field gathering, processing and certain other facilities are recorded at cost. Ordinary maintenance and repair costs are expensed as incurred.

Depreciation, depletion and amortization

Capitalized exploratory and developmental drilling costs, including lease and well equipment and intangible development costs are depreciated and amortized using the units-of-production method based on estimated proved developed oil and gas reserves on a field basis or concession basis for our international properties. International concession reserve estimates are limited to production quantities estimated through the life of the concession. Depletion of producing leasehold costs is based on the units-of-production method using estimated total proved oil and gas reserves on a field basis. In arriving at rates under the units-of-production methodology, the quantities of proved oil and gas reserves are established based on estimates made by our geologists and engineers.

Costs related to gathering, processing and certain other facilities are depreciated on the straight-line method over the estimated useful lives.

Gains or losses from the ordinary sale or retirement of properties and equipment are recorded in other—net included in operating income (loss).

Impairment of long-lived assets

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the book value of the assets, then a subsequent analysis is performed using discounted cash flows.

Costs of acquired unproved reserves are assessed for impairment using estimated fair value determined through the use of future discounted cash flows on a field basis and considering market participants' future drilling plans.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows and an asset's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs, and appropriate discount rates.

Contingent liabilities

Owing to the nature of our business, we are routinely subject to various lawsuits, claims and other proceedings. We recognize a liability in our consolidated financial statements when we determine that it is probable that a loss has been incurred and the amount can be reasonably estimated. If we determine that a loss is probable but lack information on which to reasonably estimate a loss, if any, or if we determine that a loss is only reasonably possible, we do not recognize a liability. We disclose the nature of loss contingencies that are potentially material but for which no liability has been recognized.

Asset retirement obligations

We record an asset and a liability upon incurrence equal to the present value of each expected future ARO. These estimates include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market risk premium. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense in lease and facility operating expense included in costs and expenses.

Goodwill

As a result of significant declines in forward natural gas prices during 2010, we performed an interim impairment assessment of our goodwill related to our domestic production reporting unit. As a result of that assessment, we recorded an impairment of goodwill of approximately $1 billion and no longer have any goodwill recorded on the Consolidated Balance Sheets related to our domestic operations (see Note 15).

Judgments and assumptions are inherent in our management's estimate of future cash flows used to determine the estimate of the reporting unit's fair value.

Cash flows from revolving credit facilities

Proceeds and payments related to any borrowings under our credit facilities are reflected in the financing activities of the Consolidated Statements of Cash Flows on a gross basis.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheets in derivative assets and derivative liabilities as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

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

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

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

For many of our commodity derivatives entered into prior to January 1, 2012, we designated a hedging relationship. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We established hedging relationships pursuant to our risk management policies. We evaluated the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in revenues or costs and operating expenses dependent upon the underlying hedge transaction.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in accumulated other comprehensive income (loss) ("AOCI") and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in revenues. Gains or losses deferred in AOCI associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in AOCI until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in AOCI is recognized in revenues at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

Certain gains and losses on derivative instruments included in the Consolidated Statements of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially;

- Realized gains and losses on derivatives held for trading purposes; and
- Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Product revenues

Revenues for sales of natural gas, natural gas liquids, and oil and condensate are recognized when the product is sold and delivered. Revenues from the production of natural gas in properties for which we have an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Our cumulative net natural gas imbalance position based on market prices as of December 31, 2012 and 2011 was insignificant. Additionally, natural gas revenues include $423 million in 2012, $326 million in 2011 and $333 million in 2010 of realized gains from derivatives designated as cash flow hedges of our production sold.

Gas management revenues and expenses

Revenues for sales related to gas management activities are recognized when the product is sold and physically delivered. Our gas management activities through April 2012 included purchases and subsequent sales to Williams Partners for fuel and shrink gas (see Note 3). Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges. The Company also sells natural gas purchased from working interest owners in operated wells and other area third party producers. The revenues and expenses related to these marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Charges for unutilized transportation capacity included in gas management expenses were $46 million in 2012, $35 million in 2011 and $44 million in 2010.

Capitalization of interest

We capitalize interest during construction on projects with construction periods of at least three months or a total estimated project cost in excess of $1 million. The interest rate used until June 30, 2011 was the rate charged to us by Williams through June 30, 2011, at which time our intercompany note with Williams was forgiven (see Note 3). We did not capitalize interest for the period from July 1, 2011 to mid November 2011. Beginning November 2011, we began using the weighted average rate of our long-term notes payable which were issued in November 2011 (see Note 9).

Income taxes

Beginning with the 2012 tax year, we will file initial consolidated and combined federal and state income tax returns for the Company and its subsidiaries. Through the effective date of the spin-off, the Company's domestic operations were included in the consolidated and combined federal and state income tax returns for

Williams, except for certain separate state filings. The income tax provisions for 2011 and 2010 were calculated on a separate return basis for us and our subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected benefit to us could not be determined until the date of deconsolidation. We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years.

Employee stock-based compensation

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of grant and can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options generally expire ten years after the grant.

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

Through the date of the spin-off, certain employees providing direct service to us participated in Williams' common-stock-based awards plans. The plans provided for Williams' common-stock-based awards to both employees and Williams' non-management directors. The plans permitted the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards were granted for no consideration other than prior and future services or based on certain financial performance targets.

Through the date of the spin-off, Williams charged us for compensation expense related to stock-based compensation awards granted to our direct employees. Stock based compensation was also a component of allocated amounts charged to us by Williams for general and administrative personnel providing services on our behalf.

In preparation for the spin-off, Williams' Compensation Committee determined that all outstanding Williams' equity-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 ("Pre-2006 Options") would convert into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options were converted into options covering both Williams and WPX common stock. The number of shares underlying each award and, with respect to options, the per share exercise price of each such award has been adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of such awards.

Foreign exchange

Translation gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the United States dollar are included in the results of operations as incurred.

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. Diluted earnings (loss) per common share includes any dilutive effect of stock options and nonvested restricted stock units, unless otherwise noted. The impact of our December 31, 2011 stock issuance has been given effect to all periods prior to 2011 (see Note 5).

Note 2. Discontinued Operations

During the first quarter of 2012, our management signed an agreement to divest its holdings in the Barnett Shale and the Arkoma Basin. The transaction closed in second-quarter 2012. Total proceeds received from the sale were $306 million. The Barnett Shale properties included approximately 27,000 net acres, interests in 320 wells and 91 miles of pipeline. The Arkoma properties included approximately 66,000 net acres, interests in 525 wells and 115 miles of pipeline.

Summarized Results of Discontinued Operations

	2012	2011	2010
		(Millions)	
Revenues	$ 28	$ 118	$ 115
Income (loss) from discontinued operations before impairments, gain on sale and income taxes	$ (3)	$ (15)	$ (41)
Gain on sale	38	—	—
Impairments	—	(209)	(503)
Less: Provision (benefit) for income taxes	13	(82)	(198)
Income (loss) from discontinued operations	$ 22	$(142)	$(346)

The impairments in 2011 and 2010 reflect write-downs to estimates of fair value of our holdings in the Barnett Shale and the Arkoma Basin. Impairment charges on our Fort Worth (Barnett Shale) properties were $180 million and $503 million in 2011 and 2010, respectively. Impairment charges in Arkoma were $29 million in 2011. These nonrecurring fair value measurements, which fall within Level 3 of the fair value hierarchy, utilized a probability-weighted discounted cash flow analysis that was based on internal cash flow models.

Note 3. Transactions with Williams

During the fourth quarter of 2011, the Contribution and recapitalization of the Company was completed, whereby common stock held by Williams converted into approximately 197 million shares of WPX common stock. We also entered into agreements with Williams in connection with our separation from Williams. These agreements include:

- A Separation and Distribution agreement for, among other things, the separation from Williams and the distribution of WPX common stock, the distribution of a portion of the net proceeds from the debt financing as well as agreements between us and Williams, including those relating to indemnification;
- A tax sharing agreement, providing for, among other things, the allocation between Williams and WPX of federal, state, local and foreign tax liabilities for periods prior to the distribution and in some instances for periods after the distribution;
- An employee matters agreement discussed below; and
- A transition services agreement for one year following separation.

Personnel and related services

As previously discussed, our domestic operations were contributed to WPX Energy, Inc. on July 1, 2011. On June 30, 2011, certain entities that were contributed to us on July 1, 2011 withdrew from the Williams' benefit plans and terminated their personnel services agreements with Williams' payroll companies.

Simultaneously, two new administrative service entities owned and controlled by Williams executed new personnel services agreements with the payroll companies and joined the Williams plans as participants. The effect of these transactions is that none of the companies contributed to WPX Energy in June 2011 had any employees. Through December 30, 2011, these service entities employed all personnel that provided services to the Company and remained owned and controlled by Williams.

In connection with the spin-off, we entered into an Employee Matters Agreement with Williams that set forth our agreements with Williams as to certain employment, compensation and benefits matters. The Employee Matters Agreement provides for the allocation and treatment of assets and liabilities arising out of employee compensation and benefit programs in which our employees participated prior to January 1, 2012. In connection with the spin-off, we provided benefit plans and arrangements in which our employees will participate going forward. Generally, other than with respect to equity compensation (discussed below), from and after January 1, 2012, we sponsored and maintained employee compensation and benefit programs relating to all employees who transferred to us from Williams in connection with the spin-off through the contribution of two newly established service entities that employees of Williams were moved to prior to the spin-off. The Employee Matters Agreement provides that Williams will remain solely responsible for all liabilities under The Williams Companies Pension Plan, The Williams Companies Retirement Restoration Plan and The Williams Companies Investment Plus Plan. No assets and/or liabilities under any of those plans transferred to us or our benefit plans and our employees ceased active participation in those plans as of January 1, 2012. At December 31, 2011, certain paid time off accruals approximating $13 million were transferred from Williams to us and have been reflected in accrued liabilities.

All outstanding Williams equity awards (other than stock options granted prior to January 1, 2006) held by our employees as of the spin-off were converted into WPX equity awards, issued pursuant to a plan that we established (see Note 13). In addition, outstanding Williams stock options that were granted prior to January 1, 2006 and held by our employees and Williams' other employees as of the date of the spin-off were converted into options to acquire both WPX common stock and Williams common stock, in the same proportion as the number of shares of WPX common stock that each holder of Williams common stock received in the spin-off. The conversion maintained the same intrinsic value as the applicable Williams equity award as of the date of the conversion.

Through the date of the spin-off, Williams charged us for the payroll and benefit costs associated with operations employees (referred to as direct employees) and carried the obligations for many employee-related benefits in its financial statements, including the liabilities related to employee retirement and medical plans. Our share of those costs was charged to us through affiliate billings and reflected in lease and facility operating and general and administrative within costs and expenses in the accompanying Consolidated Statements of Operations.

In addition, Williams charged us for certain employees of Williams who provided general and administrative services on our behalf (referred to as indirect employees). These charges were either directly identifiable or allocated to our operations. Direct charges included goods and services provided by Williams at our request. Allocated general corporate costs were based on our relative usage of the service or on a three-factor formula, which considers revenues; properties and equipment; and payroll. Our share of direct general and administrative expenses and our share of allocated general corporate expenses was reflected in general and administrative expense in the accompanying Consolidated Statements of Operations. In management's estimation, the allocation methodologies used were reasonable and resulted in a reasonable allocation to us of our costs of doing business incurred by Williams.

Other arrangements with Williams or its affiliates

We also have operating activities with Williams Partners and another Williams subsidiary. For the years of 2011 and 2010, the following were considered related party transactions. Beginning January 1, 2013, Williams and its subsidiaries were no longer related parties, therefore only amounts related to 2011 and 2010 are disclosed as related parties. Our revenues include revenues from the following types of transactions:

- Sales of NGLs related to our production to Williams Partners at market prices at the time of sale and included within our oil and gas sales revenues; and
- Sales to Williams Partners and another Williams subsidiary of natural gas procured by WPX Energy Marketing for those companies' fuel and shrink replacement at market prices at the time of sale and included in our gas management revenues.

Our costs and operating expenses include the following services provided by Williams Partners:

- Gathering, treating and processing services under several contracts for our production primarily in the San Juan and Piceance Basins; and
- Pipeline transportation for both our oil and gas sales and gas management activities which included commitments totaling $401 million at December 31, 2011.

During fourth-quarter 2010, the Company sold certain gathering and processing assets in Colorado's Piceance Basin (the "Piceance Sale") with a net book value of $458 million to Williams Partners, an entity under the common control of Williams, in exchange for $702 million in cash and 1.8 million Williams Partners limited partner units. As the Company and Williams Partners were under common control at that time, no gain was recognized on this transaction in the Consolidated Statements of Operations. Accordingly, the $244 million difference between the cash consideration received and the historical net book value of the assets has been reflected in the Consolidated Statements of Equity for the year ended December 31, 2010. Since the Williams Partners units received in this transaction by the Company were intended to be (and were, as described below) distributed through a dividend to Williams, these units (as well as the tax effects associated with these units of $42 million) have been presented net within equity and are included in net transfers with Williams in 2010. Further, as a result of the limitations on the Company's ability to sell these units and the subsequent dividend to Williams, no gains on the value of the common units during the holding period were recognized in the Consolidated Statements of Operations. In conjunction with the Piceance Sale, we entered into long-term contracts with Williams Partners for gathering and processing of our natural gas production in the area. Due to the continuation of significant direct cash flows related to these assets, historical operating results of these assets have been presented in the Consolidated Statements of Operations as continuing operations for periods prior to the sale. In March 2011, the 1.8 million Williams Partners units and related tax basis were distributed via dividend to Williams.

We have managed a transportation capacity contract for Williams Partners. To the extent the transportation is not fully utilized or does not recover full-rate demand expense, Williams Partners reimburses us for these transportation costs. These reimbursements to us totaled approximately $11 million and $10 million for the years ended December 31, 2011 and 2010, respectively, and are included in gas management revenues. We signed an agreement with Williams Partners under which these contracts were assigned to them effective May 1, 2012.

Prior to December 1, 2011, we participated in Williams' centralized approach to cash management and the financing of its businesses. Daily cash activity from our domestic operations was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011, at which time the notes were cancelled by Williams.

The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in owner's net investment. Through fourth-quarter 2011, an additional $162 million was cancelled and reflected as an increase in owner's net investment. The notes reflected interest based on Williams' weighted average cost of debt and such interest was added monthly to the note principle. The interest rate for the notes payable to Williams was 8.08 percent at June 30, 2011 and December 31, 2010, respectively.

On August 25, 2011, we entered into a 10.5 year lease for our present headquarters office with Williams Headquarters Building Company, a direct subsidiary of Williams. We estimate the annual rent payable by us under the lease to be approximately $4 million per year.

Below is a summary for 2011 and 2010 of the transactions with Williams or its affiliates (including amounts in discontinued operations) discussed above:

	2011	2010
	(Millions)	
Product revenues—sales of NGLs to Williams Partners	$258	$277
Gas management revenues—sales of natural gas for fuel and shrink to Williams Partners and another Williams subsidiary	586	509
Lease and facility operating expenses from Williams-direct employee salary and benefit costs	21	23
Gathering, processing and transportation expense from services with Williams Partners:		
Gathering and processing	298	163
Transportation	44	25
General and administrative from Williams:		
Direct employee salary and benefit costs	111	102
Charges for general and administrative services	62	58
Allocated general corporate costs	62	64
Other	16	12
Interest expense on notes payable to Williams	96	119

In addition, the current amount due to or from affiliates at December 31, 2011 consisted of trade receivables and payables resulting from the sale of products to and cost of gathering services provided by Williams Partners. Below is a summary of these payables and receivables and other assets and liabilities with Williams and its affiliates at December 31, 2011:

	December 31, 2011
	(Millions)
Current:	
Accounts receivable:	
Due from Williams Partners and another Williams subsidiary	$62
Other noncurrent assets—Due from Williams	$11
Accounts payable:	
Due to Williams Partners	$35
Due to Williams for accrued payroll and benefits	10
Due to Williams for administrative expenses	14
	$59
Noncurrent liability to Williams	$48

Note 4. Investment Income and Other

Investment income

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Equity earnings	$ 30	$24	$20
Other	—	2	1
Total investment income and other	$ 30	$26	$21

Investments

	December 31,	
	2012	2011
	(Millions)	
Petrolera Entre Lomas S.A.—40.8%	$109	$ 90
Other	36	35
	$145	$125

Petrolera Entre Lomas S.A. operates several development concessions in South America. Other is comprised of investments in miscellaneous gas gathering interests in the United States.

Dividends and distributions received from companies accounted for by the equity method were $12 million in 2012, $17 million in 2011 and $19 million in 2010.

Summarized Financial Position and Results of Operations of Equity Method Investments (Unaudited)

	December 31,	
	2012	2011
	(Millions)	
Current assets	$100	$ 81
Noncurrent assets	512	491
Current liabilities	133	75
Noncurrent liabilities	31	106

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Gross revenue	$383	$323	$227
Operating income	150	122	110
Net income	107	90	79

Note 5. Earnings (Loss) Per Common Share from Continuing Operations

	Years Ended December 31,		
	2012	2011	2010
	(Millions, except per-share amounts)		
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$ (245)	$ (160)	$ (945)
Basic weighted-average shares	198.8	197.1	197.1
Diluted weighted-average shares	198.8	197.1	197.1
Earnings (loss) per common share from continuing operations:			
Basic	$(1.23)	$(0.81)	$(4.80)
Diluted	$(1.23)	$(0.81)	$(4.80)

On December 31, 2011, 197.1 million shares of our common stock were distributed to Williams' shareholders in conjunction with our spin-off. For comparative purposes, and to provide a more meaningful calculation for weighted average shares, we have assumed this amount of common stock to be outstanding as of the beginning of each period presented for 2011 and 2010 in the calculation of basic and diluted weighted average shares.

For 2012 and 2011, approximately 1.9 million and 2.9 million, respectively, weighted-average nonvested restricted stock units and 1.0 million and 1.2 million, respectively, weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to WPX Energy, Inc.

The table below includes information related to stock options that were outstanding at December 31, 2012 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the fourth-quarter weighted-average market price of our common shares.

	2012
Options excluded (millions)	1.3
Weighted-average exercise price of options excluded	$18.17
Exercise price range of options excluded	$16.46 – $20.97
Fourth quarter weighted-average market price(a)	$16.15

(a) Our stock began trading on the New York Stock Exchange on January 3, 2012; therefore, a fourth quarter weighted-average market price is not available for 2011.

Note 6. Asset Sales, Impairments, Exploration Expenses and Other Accruals

The following table presents a summary of significant gains or losses reflected in impairment of producing properties and costs of acquired unproved reserves, goodwill impairment, and other—net within costs and expenses. These significant adjustments are primarily associated with our domestic operations.

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Goodwill impairment	$—	$—	$1,003
Impairment of producing properties and costs of acquired unproved reserves(a)	$225	$367	$ 175
Gain on sales of other assets	$ 4	$ 1	$ 22

(a) Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.

As a result of declines in forward natural gas and natural gas liquids prices during 2012 as compared to forward natural gas and natural gas liquids prices as of December 31, 2011, we performed impairment assessments of our proved producing properties and capitalized cost of acquired unproved reserves during 2012. Accordingly, we recorded impairments of $48 million of proved producing oil and gas properties in the Green River Basin. Additionally, we recorded a total of $102 million and $75 million in impairments of capitalized costs of acquired unproved reserves primarily in the Powder River Basin and Piceance Basin, respectively. Our impairment analyses included an assessment of undiscounted and discounted future cash flows, which considered information obtained from drilling, other activities and reserves quantities (see Note 15).

As part of our assessment for impairments primarily resulting from declining forward natural gas prices during the fourth-quarter 2011, we recorded a $276 million impairment of proved producing oil and gas properties in the Powder River Basin (see Note 15). Additionally, we recorded a $91 million impairment of our capitalized cost of acquired unproved reserves in the Powder River Basin.

As a result of significant declines in forward natural gas prices during 2010, we performed an impairment assessment of our capitalized costs related to goodwill and domestic producing properties. As a result of these assessments, we recorded an impairment of goodwill, as noted above, and an impairment of our capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million (see Note 15).

Our impairment analyses included an assessment of undiscounted (except for the costs of acquired unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities and natural gas reserve quantities.

In July 2010, we sold a portion of gathering and processing facilities in the Piceance Basin to a third party for cash proceeds of $30 million resulting in a gain of $12 million. The remaining portion of the facilities was part of the Piceance Sale (see Note 3). Also in 2010, we exchanged undeveloped leasehold acreage in different areas with a third party resulting in a $7 million gain.

Exploration Expense

The following presents a summary of exploration expense:

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Geologic and geophysical costs	$21	$ 18	$21
Dry hole costs	4	13	17
Unproved leasehold property impairment, amortization and expiration	58	95	19
Total exploration expense	$83	$126	$57

Dry hole costs in 2011 reflect an $11 million dry hole expense in connection with a Marcellus Shale well in Columbia County, Pennsylvania, while 2010 reflects dry hole expense associated primarily with wells in the Paradox Basin.

Unproved leasehold impairment, amortization and expiration in 2011 includes a $50 million write-off of leasehold costs associated with certain portions of our Columbia County, Pennsylvania acreage that we did not plan to develop.

Note 7. Properties and Equipment

Properties and equipment is carried at cost and consists of the following:

	Estimated Useful Life(a) (Years)	December 31,	
		2012	2011
		(Millions)	
Proved properties	(b)	$11,267	$ 9,806
Unproved properties	(c)	1,156	1,528
Gathering, processing and other facilities	15-25	247	89
Construction in progress	(c)	497	677
Other	3-40	172	99
Total properties and equipment, at cost		13,339	12,199
Accumulated depreciation, depletion and amortization		(4,923)	(3,977)
Properties and equipment—net		$ 8,416	$ 8,222

(a) Estimated useful lives are presented as of December 31, 2012.

(b) Proved properties are depreciated, depleted and amortized using the units-of-production method (see Note 1).

(c) Unproved properties and construction in progress are not yet subject to depreciation and depletion.

Unproved properties consist primarily of non-producing leasehold in the Appalachian Basin (Marcellus Shale) and the Williston Basin (Bakken Shale) and costs of acquired unproved reserves in the Powder River and Piceance Basins.

Construction in progress includes $65 million in 2012 and $113 million in 2011 related to wells located in Powder River. In order to produce gas from the coal seams, an extended period of dewatering is required prior to natural gas production.

Asset Retirement Obligations

Our asset retirement obligations relate to producing wells, gas gathering well connections and related facilities. At the end of the useful life of each respective asset, we are legally obligated to plug producing wells and remove any related surface equipment and to cap gathering well connections at the wellhead and remove any related facility surface equipment.

A rollforward of our asset retirement obligations for the years ended 2012 and 2011 is presented below.

	2012	2011
	(Millions)	
Balance, January 1	$289	$274
Liabilities incurred during the period	19	20
Liabilities settled during the period	(7)	(2)
Estimate revisions	(1)	(23)
Accretion expense(a)	21	20
Balance, December 31	$321	$289
Amount reflected as current	$ 5	$ 6

(a) Accretion expense is included in lease and facility operating expense on the Consolidated Statements of Operations.

Estimate revisions in 2011 are primarily associated with changes in anticipated well lives and plug and abandonment costs.

Note 8. Accounts Payable and Accrued and Other Current Liabilities

Accounts Payable

	December 31,	
	2012	2011
	(Millions)	
Trade	$209	$331
Accrual for capital expenditures	126	207
Royalties	106	111
Cash overdrafts	34	28
Other	34	25
	$509	$702

Accrued and other current liabilities

	December 31,	
	2012	2011
	(Millions)	
Taxes other than income taxes	$ 54	$ 79
Accrued interest	42	13
Compensation and benefit related accruals	52	13
Other, including other loss contingencies	55	81
	$203	$186

Note 9. Debt and Banking Arrangements

As of the indicated dates, our debt consisted of the following:

	December 31,	
	2012(a)	2011
	(Millions)	
5.250% Senior Notes due 2017	$ 400	$ 400
6.000% Senior Notes due 2022	1,100	1,100
Other	—	1
Apco	8	2
	$1,508	$1,503

(a) Interest paid on debt for 2012 totaled $58 million.

Senior Notes

In November 2011, we issued $1.5 billion in face value Senior Notes ("the Notes"). The Notes were issued under an indenture between us and The Bank of New York Mellon Trust Company, N.A., as trustee. The net proceeds from the offering of the Notes were approximately $1.481 billion after deducting the initial purchasers' discounts and our offering expenses. We retained $500 million of the net proceeds from the issuance of the Notes and distributed the remainder of the net proceeds from the issuance of the Notes, approximately $981 million, to Williams in connection with the Contribution.

Optional Redemption. We have the option, prior to maturity, in the case of the 2017 notes, and prior to October 15, 2021 (which is three months prior to the maturity date of the 2022 notes) in the case of the 2022 notes, to redeem all or a portion of the Notes of the applicable series at any time at a redemption price equal to the greater of (i) 100% of their principal amount and (ii) the discounted present value of 100% of their principal amount and remaining scheduled interest payments, in either case plus accrued and unpaid interest to the redemption date. We also have the option at any time on or after October 15, 2021, to redeem the 2022 notes, in whole or in part, at a redemption price equal to 100% of their principal amount, plus accrued and unpaid interest thereon to the redemption date.

Change of Control. If we experience a change of control (as defined in the indenture governing the Notes) accompanied by a rating decline with respect to a series of Notes, we must offer to repurchase the Notes of such series at 101% of their principal amount, plus accrued and unpaid interest.

Covenants. The terms of the indenture restrict our ability and the ability of our subsidiaries to incur additional indebtedness secured by liens and to effect a consolidation, merger or sale of substantially all our assets. The indenture also requires us to file with the trustee and the SEC certain documents and reports within certain time limits set forth in the indenture. However, these limitations and requirements will be subject to a number of important qualifications and exceptions. The indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity.

Events of Default. Each of the following is an "Event of Default" under the indenture with respect to the Notes of any series:

(1) a default in the payment of interest on the Notes when due that continues for 30 days;

(2) a default in the payment of the principal of or any premium, if any, on the Notes when due at their stated maturity, upon redemption, or otherwise;

(3) failure by us to duly observe or perform any other of the covenants or agreements (other than those described in clause (1) or (2) above) in the indenture, which failure continues for a period of 60 days, or, in the case of the reporting covenant under the indenture, which failure continues for a period of 90 days, after the date on which written notice of such failure has been given to us by the trustee; provided, however, that if such failure is not capable of cure within such 60-day or 90-day period, as the case may be, such 60-day or 90-day period, as the case may be, will be automatically extended by an additional 60 days so long as (i) such failure is subject to cure and (ii) we are using commercially reasonable efforts to cure such failure; and

(4) certain events of bankruptcy, insolvency or reorganization described in the indenture.

Notes Registration. In June 2012, we completed an exchange offer whereby we exchanged our privately-placed Notes for like principal amounts of registered 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022. The exchange offer fulfilled our obligations under the registration rights agreement that we entered into as part of the November 2011 issuance.

Credit Facility Agreement

During 2011, we entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the "Credit Facility Agreement"). Under the terms of the Credit Facility Agreement and subject to certain requirements, we may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. The Credit Facility Agreement became effective November 1, 2011. At December 31, 2012 there were no amounts outstanding under the Credit Facility Agreement.

Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at our option: (1) a fluctuating base rate equal to the Alternate Base Rate plus the Applicable Rate, or (2) a periodic fixed rate equal to LIBOR plus the Applicable Rate. The Alternate Base Rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. The Applicable Rate changes depending on which interest rate we select and our credit rating. Additionally, we will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility Agreement.

Under the Credit Facility Agreement, prior to the occurrence of the Investment Grade Date (as defined below), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (each as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. Net present value is determined as of the end of each fiscal year and reflects the present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves (such cash flows are adjusted to reflect the impact of hedges, our lenders' commodity price forecasts, and, if necessary, to include only a portion of our reserves that are not proved developed producing reserves). Additionally, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. We were in compliance with our debt covenant ratios as of December 31, 2012. Investment Grade Date means the first date on which our long-term senior unsecured debt ratings are BBB- or better by S&P or Baa3 or better by Moody's (without negative outlook or negative watch), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody's.

The Credit Facility Agreement contains customary representations and warranties and affirmative, negative and financial covenants which were made only for the purposes of the Credit Facility Agreement and as of the specific date (or dates) set forth therein, and may be subject to certain limitations as agreed upon by the contracting parties. The covenants limit, among other things, the ability of our subsidiaries to incur indebtedness, make investments, loans or advances and enter into certain hedging agreements; our ability to merge or consolidate with any person or sell all or substantially all of our assets to any person, enter into certain affiliate transactions, make certain distributions during the continuation of an event of default and allow material changes in the nature of our business. In addition, the representations, warranties and covenants contained in the Credit Facility Agreement may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors.

The Credit Facility Agreement includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to us occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of any loans outstanding under the Credit Facility Agreement at the time, in addition to the exercise of other rights and remedies available.

Letters of Credit

In addition to the Notes and Credit Facility Agreement, WPX has entered into three bilateral, uncommitted letter of credit ("LC") agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility Agreement. At December 31, 2012 a total of $312 million in letters of credit have been issued.

Apco

Apco has a loan agreement with a financial institution for a $10 million bank line of credit. The funds could be borrowed during a one-year period which ended in March 2012. As of December 31, 2012, Apco has borrowed $8 million under this banking agreement. Principal amounts will be repaid in installments through 2016. This debt agreement contains covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, purchase or sell assets outside the ordinary course of business, and incur additional debt.

Note 10. Provision (Benefit) for Income Taxes

The provision (benefit) for income taxes from continuing operations includes:

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Provision (benefit):			
Current:			
Federal	$ 48	$ 49	$ 72
State	3	7	5
Foreign	14	10	11
	65	66	88
Deferred:			
Federal	(162)	(139)	(41)
State	(13)	(1)	(3)
Foreign	(1)	—	—
	(176)	(140)	(44)
Total provision (benefit)	$(111)	$ (74)	$ 44

Reconciliations from the provision (benefit) for income taxes from continuing operations at the federal statutory rate to the realized provision (benefit) for income taxes are as follows:

	Years Ended December 31,		
	2012	2011	2010
		(Millions)	
Provision (benefit) at statutory rate	$(120)	$ (79)	$(313)
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(7)	(5)	2
Effective state income tax rate change (net of federal benefit)	—	9	—
Alternative minimum tax credits	11	—	—
Foreign operations—net	4	—	4
Goodwill impairment	—	—	351
Other—net	1	1	—
Provision (benefit) for income taxes	$(111)	$ (74)	$ 44

Income (loss) from continuing operations before income taxes includes $52 million, $40 million and $36 million of foreign income in 2012, 2011 and 2010, respectively.

Significant components of deferred tax liabilities and deferred tax assets are as follows:

	December 31,	
	2012	2011
	(Millions)	
Deferred tax liabilities:		
Properties and equipment	$1,652	$1,779
Other, net	19	137
Total deferred tax liabilities	1,671	1,916
Deferred tax assets:		
Accrued liabilities and other	176	146
Alternative minimum tax credits	99	98
Loss carryovers	31	16
Total deferred tax assets	306	260
Less: valuation allowance	19	16
Total net deferred tax assets	287	244
Net deferred tax liabilities	$1,384	$1,672

Through the effective date of the spin-off, the Company's domestic operations were included in the consolidated and combined federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision for 2011 and 2010 has been calculated on a separate return basis for the Company and its consolidated subsidiaries, except for certain adjustments such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected impact to the Company could not be determined until the date of deconsolidation. Effective with the spin-off, Williams and the Company entered into a tax sharing agreement which governs the respective rights, responsibilities and obligations of each company, for tax periods prior to the spin-off, with respect to the payment of taxes, filing of tax returns, reimbursements of taxes, control of audits and other tax proceedings, liability for taxes that may be triggered as a result of the spin-off and other matters regarding taxes.

In connection with the spin-off, alternative minimum tax credits were estimated and allocated between Williams and the Company effective December 31, 2011. This resulted in the allocation to the Company of a $98 million deferred tax asset with a corresponding increase to additional paid-in-capital. Subsequent to the spin-off, Williams notified the Company of certain corrections that resulted in $15 million of reductions in the alternative minimum tax credit allocated to the Company of which $11 million is reflected within provision (benefit) for income taxes in 2012. Additionally, the Company expects to have alternative minimum tax liability for 2012.

As of December 31, 2012, the Company has approximately $500 million of state net operating loss carryovers of which approximately 99 percent expire after 2022. The Company assesses available positive and negative evidence to estimate if sufficient future taxable income will be generated in a particular state to utilize the net operating loss carryover for that state. Based on that assessment, a valuation allowance was recorded at December 31, 2012 and 2011 to reduce the recognized tax assets associated with state losses, net of federal benefit, to an amount that will more likely than not be realized by the Company.

Undistributed earnings of certain consolidated foreign subsidiaries excluding amounts related to foreign equity investments at December 31, 2012, totaled approximately $77 million. No provision for deferred U.S. income taxes has been made for these subsidiaries, except with respect to foreign equity investments, because the Company intends to permanently reinvest such earnings in foreign operations.

Cash payments for domestic income taxes (net of receipts) were $40 million, $10 million and $5 million in 2012, 2011 and 2010, respectively. Additionally, payments made directly to international taxing authorities were $11 million, $10 million and $8 million in 2012, 2011 and 2010, respectively. The payments and receipts for domestic income taxes for 2011 and 2010 (prior to the spin-off) were made to or received from Williams in accordance with Williams' intercompany tax allocation procedure.

The Company's policy is to recognize related interest and penalties as a component of income tax expense. The amounts accrued for interest and penalties are insignificant.

Pursuant to our tax sharing agreement with Williams, we will remain responsible for the tax from audit adjustments related to our business for periods prior to the spin-off. During the third quarter of 2012, Williams finalized settlements with the IRS for 2009 and 2010. The statute of limitations for most states expires one year after expiration of the IRS statute. Income tax returns for our foreign operations, primarily in Argentina, are open to audit for the 2005 to 2012 tax years.

As of December 31, 2012, the Company has no significant unrecognized tax benefits. During the next 12 months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter will result in a significant increase or decrease of an unrecognized tax benefit.

Note 11. Contingent Liabilities and Commitments

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County, Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for proceeds received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments related to calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class for certification, resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim is whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate litigating the second reserved claim in 2013. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint alleges failure to pay royalty on hydrocarbons including drip condensate, fraud and misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons, violation of the New Mexico Oil and Gas Proceeds Payment Act, bad faith breach of contract and unjust enrichment. Plaintiffs seek monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter has been removed to the United States District Court for New Mexico. In August 2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico, violation of the New Mexico Oil and Gas Proceeds Payment Act and seek declaratory judgment, accounting and injunction. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we are monitoring them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue ("ONRR") in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR's guidance provides its view as to how much of a producer's bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states though such guidelines are expected in the future. However, the timing of any such guidance is uncertain. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR's assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR's predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From October 2005 through December 2012, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $116 million.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that we have underpaid royalties due per the oil and gas leases with the State of New Mexico. In August 2011, the parties agreed to stay this matter pending the New Mexico Supreme Court's resolution of a similar matter involving a different producer. At this time, we do not have a sufficient basis to calculate an estimated range of exposure related to this claim.

Environmental matters

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, one hour nitrogen dioxide emission limits, and hydraulic fracturing and water standards. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matters related to Williams' former power business

In connection with the Separation and Distribution Agreement, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us, and we are obligated to pay Williams any net proceeds realized from, the pending or threatened litigation described below relating to the 2000-2001 California energy crisis and the reporting of certain natural gas-related information to trade publications.

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. We have entered into settlements with the State of California ("State Settlement"), major California utilities ("Utilities Settlement"), and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We currently have a settlement agreement in principle with certain California utilities aimed at substantially reducing this exposure. Once finalized, the settlement agreement will also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement will resolve most, if not all, of our legal issues arising from the 2000-2001 California energy crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of natural gas-related information to trade publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, seeking unspecified amounts of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, and Wisconsin and brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs' lack of standing. On January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal and entered judgment in our favor. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs' state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time.

Other Indemnifications

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

At December 31, 2012, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In connection with the separation from Williams, we have agreed to indemnify and hold Williams harmless from any losses resulting from the operation of our business or arising out of liabilities assumed by us. Similarly, Williams has agreed to indemnify and hold us harmless from any losses resulting from the operation of its business or arising out of liabilities assumed by it.

Summary

As of December 31, 2012 and December 31, 2011, the Company had accrued approximately $18 million and $23 million, respectively, for loss contingencies associated with royalty litigation, reporting of natural gas information to trade publications and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

Commitments

As part of managing our commodity price risk, we utilize contracted pipeline capacity to move our natural gas production and third party gas purchases to other locations in an attempt to obtain more favorable pricing differentials. Our commitments under these contracts as of December 31, 2012 are as follows:

	(Millions)
2013	$ 205
2014	211
2015	207
2016	192
2017	175
Thereafter	741
Total	$1,731

We also have certain commitments to an equity investee and others, primarily for natural gas gathering and treating services and well completion services, which total $634 million over approximately seven years.

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu per day of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. This obligation expires in 2014.

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 per day of natural gas at Transco Station 515 (Marcellus Basin) at market prices from the same third party. Purchases under the 12-year contract began in the first quarter of 2012. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

Future minimum annual rentals under noncancelable operating leases as of December 31, 2012, are payable as follows:

	(Millions)
2013	$ 63
2014	59
2015	41
2016	10
2017	8
Thereafter	29
Total	$210

Total rent expense, excluding amounts capitalized, was $20 million, $12 million and $12 million in 2012, 2011 and 2010, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting; however, charges for rig release penalties or long term standby charges are expensed as incurred.

Note 12. Employee Benefit Plans

Subsequent to spin-off

On January 1, 2012, several new plans became effective for us including a defined contribution plan. WPX matches dollar-for-dollar up to the first 6 percent of eligible pay per period. Employees also receive a non-matching annual employer contribution of equal to 8 percent of eligible pay if they are age 40 or older and 6 percent of eligible pay if they are under age 40. Contributions to this plan were $6 million in 2012 and approximately $10 million was included in accrued and other current liabilities at December 31, 2012 related to the non-matching annual employer contribution.

Prior to spin-off

Through the spin-off date, certain benefit costs associated with direct employees who support our operations are determined based on a specific employee basis and were charged to us by Williams as described below. These pension and post retirement benefit costs included amounts associated with vested participants who are no longer employees. As described in Note 3 Williams also charged us for the allocated cost of certain indirect employees of Williams who provided general and administrative services on our behalf. Williams included an allocation of the benefit costs associated with these Williams employees based upon Williams' determined benefit rate, not necessarily specific to the employees providing general and administrative services on our behalf. As a result, the information described below is limited to amounts associated with the direct employees that supported our operations.

For the periods presented, we were not the plan sponsor for these plans. Accordingly, our Consolidated Balance Sheets do not reflect any assets or liabilities related to these plans.

Pension plans

Williams is the sponsor of noncontributory defined benefit pension plans that provides pension benefits for its eligible employees. Pension expense charged to us by Williams for 2011 and 2010 totaled $8 million and $7 million, respectively.

Other postretirement benefits

Williams is the sponsor of subsidized retiree medical and life insurance benefit plans ("other postretirement benefits") that provides benefits to certain eligible participants, generally including employees hired on or before December 31, 1991, and other miscellaneous defined participant groups. Other postretirement benefit expense charged to us by Williams for 2011 and 2010 totaled less than $1 million for each period.

Defined contribution plan

Williams also is the sponsor of a defined contribution plan that provides benefits to certain eligible participants and charged us compensation expense of $4 million and $5 million in 2011 and 2010, respectively, for Williams' matching contributions to this plan.

Note 13. Stock-Based Compensation

WPX Energy, Inc. 2011 Incentive Plan

Subsequent to the spin-off, we have an equity incentive plan ("2011 Incentive Plan") and an employee stock purchase plan ("ESPP"). The 2011 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units and other stock-based awards. The number of shares of common stock authorized for issuance pursuant to all awards granted under the 2011 Incentive Plan is 11 million shares. The 2011 Incentive Plan is administered by either the full Board of Directors or a committee as designated by the Board of Directors, determined by the grant. Our employees, officers and non-employee directors are eligible to receive awards under the 2011 Incentive Plan.

The ESPP allows domestic employees the option to purchase WPX common stock at a 15 percent discount through after-tax payroll deductions. The purchase price of the stock is the lower of either the first or last day of the biannual offering periods, followed with the 15 percent discount. The maximum number of shares that shall be made available under the purchase plan is 1 million shares, subject to adjustment for stock splits and similar events. The first offering under the ESPP commenced on March 1, 2012 and ended on June 30, 2012. Subsequent offering periods are from January through June and from July through December. Employees purchased 110 thousand shares at an average price of $13.08 per share during 2012.

The Williams Companies, Inc. 2011 Incentive Plan

Certain of our direct employees participated in The Williams Companies, Inc. 2007 Incentive Plan, which provides for Williams common-stock-based awards to both employees and Williams' nonmanagement directors. The plan permits the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets. Additionally, certain of our eligible direct employees participated in Williams' ESPP. The ESPP enables eligible participants to purchase through payroll deductions a limited amount of Williams' common stock at a discounted price.

Through the date of spin-off, we were charged by Williams for stock-based compensation expense related to our direct employees. Williams also charged us for the allocated costs of certain indirect employees of Williams (including stock-based compensation) who provide general and administrative services on our behalf. However, information included in this note is limited to stock-based compensation associated with the direct employees for years prior to 2012. See Note 3 for total costs charged to us by Williams.

Williams' Compensation Committee determined that all outstanding Williams stock-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 (the "Pre-2006 Options"), be converted into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options (whether held by our employees or other Williams employees) converted into options for both Williams and WPX common stock following the spin-off, in the same ratio as is used in the distribution of WPX common stock to holders of Williams common stock. The number of shares underlying each such award (including the Pre-2006 Options) and, with respect to options (including the Pre-2006 Options), the per share exercise price of each award was adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of each award.

Employee stock-based awards

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant.

Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

Restricted stock units are generally valued at fair value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

Total stock-based compensation expense (including amount charged to us by Williams) reflected in general and administrative expense for the years ended December 31, 2012, 2011 and 2010 was $28 million, $18 million, and $14 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2012 was $43 million. This amount is comprised of $2 million related to stock options and $41 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 2.4 years.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2012.

	WPX Plan		
Stock Options	**Options**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value**
	(Millions)		(Millions)
Outstanding at December 31, 2011	4.2	$11.41	$29
Granted	0.3	$18.16	
Exercised	(0.4)	$ 4.67	
Expired	—	$ —	
Outstanding at December 31, 2012(a)	4.1	$12.68	$14
Exercisable at December 31, 2012	3.2	$11.74	$13

(a) Includes approximately 598 thousand shares held by Williams' employees at a weighted average price of $8.48 per share.

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $5 million, $7 million, and $2 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2012.

	WPX Plan					
	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life
	(Millions)		(Years)	(Millions)		(Years)
$ 5.50 to $6.76	1.0	$ 5.87	4.7	1.0	$ 5.87	4.7
$ 9.08 to $11.75	1.1	$11.28	5.0	0.9	$11.17	4.5
$12.00 to $15.67	0.7	$14.41	3.8	0.7	$14.41	3.8
$16.46 to $20.97	1.3	$18.17	7.4	0.6	$19.13	6.0
Total	4.1	$12.68	5.5	3.2	$11.74	4.7

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

	WPX Plan	
	2012	2011
Weighted-average or grant date fair value of options granted	$7.79	$ —
Weighted-average conversion date fair value options granted		$ 8.48
Weighted-average assumptions:		
Dividend yield	— %	— %
Volatility	43.8%	45%
Risk-free interest rate	1.17%	0.377%
Expected life (years)	6.0	2.8

We determined that the Williams stock option grant data was not relevant for valuing WPX options; therefore the Company used the SEC simplified method. The expected volatility is based primarily on the historical volatility of comparable peer group stocks. The risk free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life is assumed based on the SEC simplified method.

For 2011, the weighted average fair value is a component of the intrinsic value calculation at spin-off. The expected volatility yield is based on the historical volatility of comparable peer group stocks. The risk free rate interest rate is based on the U.S. Treasury Constant Maturity rates as of the modification date. The expected life of the options is based over the remaining option term.

Cash received from stock option exercises was $2 million during 2012.

Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2012.

	WPX Plan	
Restricted Stock Units	Shares	Weighted-Average Fair Value(a)
	(Millions)	
Nonvested at December 31, 2011	4.6	$ 9.69
Granted	2.8	$17.35
Forfeited	(0.2)	$16.20
Cancelled	—	$ —
Vested	(2.4)	$ 5.71
Nonvested at December 31, 2012	4.8	$16.45

(a) Performance-based shares are primarily valued using a valuation pricing model. However, certain of these shares were valued using the end-of-period market price until certification that the performance objectives were completed or a value of zero once it was determined that it was unlikely that performance objectives would be met. All other shares are valued at the grant-date market price, less dividends projected to be paid over the vesting period.

Other restricted stock unit information

	WPX Plan	Williams Plan	
	2012	2011	2010
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$17.35	$27.74	$20.00
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 14	$ 10	$ 9

Performance-based shares granted represent 13 percent of nonvested restricted stock units outstanding at December 31, 2012. These grants may be earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 14. Stockholders' Equity

Common Stock

Each share of our common stock entitles its holder to one vote in the election of each director. No share of our common stock affords any cumulative voting rights. Holders of our common stock will be entitled to dividends in such amounts and at such times as our Board of Directors in its discretion may declare out of funds legally available for the payment of dividends. No dividends were declared or paid as of December 31, 2012 or 2011. No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our Board of Directors to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action. Rights and privileges associated with shares of preferred stock are subject to authorization by our Board of Directors and may differ from those of any and all other series at any time outstanding.

Note 15. Fair Value Measurements

Fair value is the amount received from the sale of an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements primarily consist of financial instruments that are exchange traded.
- Level 2—Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 measurements primarily consist of over-the-counter ("OTC") instruments such as forwards, swaps, and options. These options, which hedge future sales of production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings.
- Level 3—Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents and restricted cash approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
			(Millions)				(Millions)	
Energy derivative assets	$ 20	$ 38	$ 2	$ 60	$ 55	$ 454	$ 7	$ 516
Energy derivative liabilities	$ 11	$ 1	$ 3	$ 15	$ 41	$ 112	$ 6	$ 159
Long-term debt(a)	$—	$1,617	$—	$1,617	$—	$1,523	$—	$1,523

(a) The carrying value of long-term debt, excluding capital leases, was $1,508 million and $1,502 million as of December 31, 2012 and 2011, respectively.

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps, options and swaptions. These are carried at fair value on the Consolidated Balance Sheets.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars or as swaptions and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with several crude oil swaps entered into, we granted crude oil swaptions to the swap counterparties in exchange for receiving premium hedged prices on the crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 98 percent of the net fair value of our derivatives portfolio expiring in the next 12 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2012, consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers between Level 1 and Level 2 occurred during the years ended December 31, 2012 or 2011. During the period ended March 31, 2011, certain NGL swaps that originated during the first quarter of 2011 were transferred from Level 3 to Level 2. Prior to March 31, 2011, these swaps were considered Level 3 due to a lack of observable third-party market quotes. Due to an increase in exchange-traded transactions and greater visibility from OTC trading, we transferred these instruments to Level 2.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Years ended December 31,		
	2012 Net Energy Derivatives	2011 Net Energy Derivatives	2010 Net Energy Derivatives
		(Millions)	
Beginning balance	$ 1	$ 1	$ 1
Realized and unrealized gains (losses):			
Included in income (loss) from continuing operations	3	15	1
Included in other comprehensive income (loss)	—	—	—
Purchases, issuances, and settlements	(5)	(12)	(1)
Transfers out of Level 3	—	(3)	—
Ending balance	$ (1)	$ 1	$ 1
Unrealized gains included in income (loss) from continuing operations relating to instruments still held at December 31	$ (1)	$ 1	$—

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statements of Operations.

For the year ending December 31, 2011, the entire $12 million reduction to level 3 fair value measurements are settlements.

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Total losses for the years ended December 31,		
	2012	2011	2010
		(Millions)	
Impairments:			
Goodwill (Note 6)	$—	$—	$1,003(c)
Producing properties and costs of acquired unproved reserves (Note 6)	225(a)	367(b)	175(d)
	$225	$367	$1,178

(a) Due to significant declines in forward natural gas and natural gas liquids prices during 2012, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future discounted cash flows. Significant judgments and assumptions in these assessments include estimates of probable and possible reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, future natural gas liquids prices, expectation for market participant drilling plans, expected capital costs and an applicable discount rate commensurate with the risk of the underlying cash flow estimates. As a result, we recorded the following impairment charges. Fair value measured for these properties at December 31, 2012 was estimated to be approximately $351 million.

- $102 million and $75 million of impairment charges related to acquired unproved reserves in Powder River and Piceance, respectively. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.
- $48 million impairment charge related to natural gas-producing properties in Green River. Significant assumptions in valuing these properties included proved reserves quantities of more than 29 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $5.87 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

(b) Due to significant declines in forward natural gas prices, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows including potential disposition proceeds. Significant judgments and assumptions in these assessments include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The annual assessment identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded the following impairment charges. Fair value measured for these properties at December 31, 2011, was estimated to be approximately $546 million.

- $276 million impairment charge related to natural gas-producing properties in Powder River. Significant assumptions in valuing these properties included proved reserves quantities of more than 352 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.81 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

- $91 million impairment charge related to acquired unproved reserves in Powder River. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.

(c) Due to a significant decline in forward natural gas prices across all future production periods during 2010, we determined that we had a trigger event and thus performed an interim impairment assessment of the approximate $1 billion of goodwill related to our domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent ("Mcfe") for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after-tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined that the implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

(d) As of September 30, 2010, we had a trigger event as a result of recent significant declines in forward natural gas prices and therefore, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $175 million impairment charge in third-quarter 2010 related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent. Fair value measured for these properties was estimated to be approximately $9 million at September 30, 2010.

Note 16. Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas, natural gas liquids and crude oil attributable to commodity price risk. Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we began entering into commodity derivative contracts that will continue to serve as economic hedges but will not be designated as cash flow hedges for accounting purposes as we have elected not to utilize this method of accounting on new derivatives instruments. Remaining commodity derivatives recorded at December 31, 2011 that were designated as cash flow hedges will realize at the end of the first quarter of 2013.

We produce, buy and sell natural gas, natural gas liquids and crude oil at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in commodity market prices, we enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas, natural gas liquids and crude oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Our financial option contracts are either purchased options, a combination of options that comprise a net purchased option or a zero-cost collar or swaptions.

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Derivatives for transportation and storage contracts economically hedge the expected cash flows generated by those agreements.

The following table sets forth the derivative volumes that are economic hedges of production volumes as well as the table depicts the notional amounts of the net long (short) positions which do not represent economic hedges of our production, both which are included in our commodity derivatives portfolio as of December 31, 2012.

Derivatives related to production

Commodity	Period	Contract Type(a)	Location	Notional Volume(b)	Weighted Average Price(c)
Crude Oil	2013	Fixed Price Swaps	WTI	(9,000)	$100.52
Natural Gas	2013	Location Swaps	Northeast	(25)	$ 4.63
Natural Gas	2013	Location Swaps	Rockies	(20)	$ 3.89
Natural Gas	2013	Location Swaps	San Juan	(10)	$ 3.93

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type(d)	Location(e)	Notional Volume(b)	Weighted Average Price(f)
Natural Gas	2013	Fixed Price Swaps	Multiple	(21)	—
Natural Gas	2013	Basis Swaps	Multiple	(27)	—
Natural Gas	2013	Index	Multiple	(81)	—
Natural Gas	2014	Basis Swaps	Multiple	(1)	—
Natural Gas	2014	Index	Multiple	(20)	—
Natural Gas	2015	Basis Swaps	Multiple	(6)	—
Natural Gas	2015	Index	Multiple	(3)	—
Natural Gas	2016	Index	Multiple	2	—
Natural Gas	2017	Index	Multiple	2	—

(a) WPX Equity Production Hedges for crude oil are business day average swaps and the natural gas hedges are fixed price at location swaps.
(b) Natural gas volumes are reported in BBtu/day and crude oil volumes are reported in Bbl/day.
(c) The weighted average price for natural gas is reported in $/MMBtu and the crude oil price is reported in $/Bbl.
(d) WPX Marketing enters into exchange traded fixed price and basis swaps, over the counter fixed price and basis swaps, physical fixed price transactions and transactions with an index component.
(e) WPX Marketing transacts at multiple locations around our core assets to maximize the economic value of our transportation, storage and asset management agreements.
(f) The weighted average price is not reported since the notional volumes represent a net position comprised of buys and sells with positive and negative transaction prices.

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheets as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	December 31,			
	2012		2011	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production designated as hedging instruments	$ 5	$—	$360	$ 13
Not designated as hedging instruments:				
Derivatives related to production not designated as hedging instruments	33	—	3	7
Legacy natural gas contracts from former power business	2	2	93	92
All other	20	13	60	47
Total derivatives not designated as hedging instruments	55	15	156	146
Total derivatives	$60	$15	$516	$159

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in accumulated other comprehensive income ("AOCI") or revenues.

	Years Ended December 31, 2012	2011	Classification
	(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$ 90	$413	AOCI
Net gain reclassified from *accumulated other comprehensive income (loss)* into income (effective portion)(a)	$434	$331	Revenues

(a) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains associated with our production reflected in natural gas sales and oil and condensate sales.

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The following table presents pre-tax gains and losses recognized in revenues for our energy commodity derivatives not designated as hedging instruments.

	Years Ended December 31, 2012	2011
	(Millions)	
Unrealized gain (loss)	$32	$(10)
Realized gain (loss)	46	39
Net gain (loss) on derivative not designated as hedges	$78	$ 29

The cash flow impact of our derivative activities is presented in the Consolidated Statements of Cash Flows as changes in current and noncurrent derivative assets and liabilities.

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, under certain events, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor's and/or Moody's Investment Services. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability.

As of December 31, 2012, we had collateral totaling $2 million posted to derivative counterparties to support the aggregate fair value of our net $5 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2011, we had collateral totaling $18 million posted to derivative counterparties to support the aggregate fair value of our net $37 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which included a reduction of less than $1 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $3 million and $19 million at December 31, 2012 and December 31, 2011, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. During the first quarter of 2012, approximately $15 million of unrealized gains were recognized into earnings in 2012 for hedge transactions where the underlying transactions were no longer probable of occurring due to the sale of our Barnett Shale properties. The $15 million gain is included in net gains (losses) on derivatives not designated as hedges on the Consolidated Statements of Operations for 2012, as are second-quarter 2012 changes in forward mark to market value. As of December 31, 2012, we have hedged portions of future cash flows associated with anticipated energy commodity sales for three months. Based on recorded values at December 31, 2012, $3 million of net gains (net of income tax provision of $2 million) will be reclassified into earnings in the first quarter of 2013. These recorded values are based on market prices of the commodities as of December 31, 2012. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next quarter could differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts receivable

The following table summarizes concentration of receivables, net of allowances, by product or service as of December 31:

	2012	2011
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services	$289	$286
Joint interest owners	138	150
Other	16	11
Total	$443	$447

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains and Gulf Coast. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2012, 2011 and 2010, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

The gross and net credit exposure from our derivative contracts as of December 31, 2012, is summarized as follows:

Counterparty Type	Gross Investment Grade(a)	Gross Total	Net Investment Grade(a)	Net Total
		(Millions)		
Gas and electric utilities, integrated oil and gas companies, and other	$ 1	$ 1	$ 1	$ 1
Energy marketers and traders	5	5	4	5
Financial institutions	54	54	44	44
	$60	60	$49	50
Credit reserves		—		—
Credit exposure from derivatives		$ 60		$ 50

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade.

Our eight largest net counterparty positions represent approximately 97 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

At December 31, 2012, we held collateral support of $4 million, either in the form of cash or letters of credit, related to our other derivative positions.

Revenues

During 2012, 2011, and 2010, BP Energy Company, a domestic segment customer, accounted for 10 percent, 11 percent and 13 percent of our consolidated revenues, respectively. During 2012, Williams accounted for 12 percent of our consolidated revenue. Prior to 2012, Williams was considered an affiliate of WPX. See Note 3 for revenue related to Williams for 2011 and 2010. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

Note 17. Segment Disclosures

Our reporting segments are domestic and international (see Note 1).

Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and international maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

Performance Measurement

We evaluate performance based upon segment revenues and segment operating income (loss). There are no intersegment sales between domestic and international.

The following tables reflect the reconciliation of segment revenues and segment operating income (loss) to revenues and operating income (loss) as reported in the Consolidated Statements of Operations. Long-lived assets are comprised of gross property, plant and equipment and long-term investments.

For the year ended December 31, 2012	Domestic	International	Total
		(Millions)	
Total revenues	$ 3,052	$137	$ 3,189
Costs and expenses:			
Lease and facility operating	$ 251	$ 32	$ 283
Gathering, processing and transportation	504	2	506
Taxes other than income	87	24	111
Gas management, including charges for unutilized pipeline capacity	996	—	996
Exploration	72	11	83
Depreciation, depletion and amortization	939	27	966
Impairment of producing properties and costs of acquired unproved reserves	225	—	225
General and administrative	273	14	287
Other—net	12	—	12
Total costs and expenses	$ 3,359	$110	$ 3,469
Operating income (loss)	$ (307)	$ 27	$ (280)
Interest expense	(102)	—	(102)
Interest capitalized	8	—	8
Investment income and other	3	27	30
Income (loss) from continuing operations before income taxes	$ (398)	$ 54	$ (344)
Other financial information:			
Net capital expenditures	$ 1,463	$ 58	$ 1,521
Total assets	$ 9,113	$343	$ 9,456
Long—lived assets	$13,056	$428	$13,484

For the year ended December 31, 2011	Domestic	International	Total
		(Millions)	
Total revenues	$ 3,772	$110	$ 3,882
Costs and expenses:			
Lease and facility operating	$ 235	$ 27	$ 262
Gathering, processing and transportation	487	—	487
Taxes other than income	113	21	134
Gas management, including charges for unutilized pipeline capacity	1,471	—	1,471
Exploration	123	3	126
Depreciation, depletion and amortization	880	22	902
Impairment of producing properties and costs of acquired unproved reserves	367	—	367
General and administrative	263	12	275
Other—net	(3)	3	—
Total costs and expenses	$ 3,936	$ 88	$ 4,024
Operating income (loss)	$ (164)	$ 22	$ (142)
Interest expense	(117)	—	(117)
Interest capitalized	9	—	9
Investment income and other	6	20	26
Income (loss) from continuing operations before income taxes	$ (266)	$ 42	$ (224)
Other financial information:			
Net capital expenditures	$ 1,531	$ 41	$ 1,572
Total assets	$10,144	$288	$10,432
Long-lived assets	$11,969	$354	$12,323

For the year ended December 31, 2010	Domestic	International	Total
		(Millions)	
Total revenues	$ 3,846	$ 89	$ 3,935
Costs and expenses:			
Lease and facility operating	$ 244	$ 19	$ 263
Gathering, processing and transportation	320	—	320
Taxes other than income	104	16	120
Gas management, including charges for unutilized pipeline capacity	1,767	—	1,767
Exploration	51	6	57
Depreciation, depletion and amortization	794	17	811
Impairment of producing properties and costs of acquired unproved reserves	175	—	175
Goodwill impairment	1,003	—	1,003
General and administrative	233	9	242
Other—net	(18)	—	(18)
Total costs and expenses	$ 4,673	$ 67	$ 4,740
Operating income (loss)	$ (827)	$ 22	$ (805)
Interest expense	(124)	—	(124)
Interest capitalized	15	—	15
Investment income and other	4	17	21
Income (loss) from continuing operations before income taxes	$ (932)	$ 39	$ (893)
Other financial information:			
Net capital expenditures	$ 1,821	$ 35	$ 1,856
Total assets	$ 9,590	$256	$ 9,846
Long—lived assets	$11,915	$306	$12,221

WPX Energy, Inc.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Millions, except per-share amounts)			
2012				
Revenues	$ 910	$ 775	$ 677	$ 827
Operating costs and expenses	834	673	680	758
Income (loss) from continuing operations	(38)	(29)	(63)	(103)
Net income (loss)	(40)	(6)	(61)	(104)
Amounts attributable to WPX Energy:				
Net income (loss)	(43)	(10)	(64)	(106)
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$(0.21)	$(0.17)	$(0.33)	$(0.53)
2011				
Revenues	$ 958	$ 959	$ 995	$ 970
Operating costs and expenses	841	807	904	830
Income (loss) from continuing operations	7	30	19	(206)
Net income (loss)	(1)	28	16	(335)
Amounts attributable to WPX Energy:				
Net income (loss)	(3)	25	14	(338)
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.03	$ 0.13	$ 0.09	$(1.06)

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to rounding.

Net loss for fourth-quarter 2012 includes the following pre-tax items:

- $108 million of impairments of producing properties and costs of acquired unproved reserves (see Note 6).

Net loss for second-quarter 2012 includes the following pre-tax items:

- $65 million of impairments of costs of acquired unproved reserves in the Powder River Basin (see Note 6).
- Gain on sale of Barnett and Arkoma properties.

Net loss for first-quarter 2012 includes the following pre-tax items:

- $52 million of impairments of costs of acquired unproved reserves primarily in the Powder River Basin (see Note 6).

Net loss for fourth-quarter 2011 includes the following pre-tax items:

- $367 million of impairments of producing properties and costs of acquired unproved reserves (see Note 6) and $193 million of impairments related to the Barrett Shale and Arkoma discontinued operations (see Note 2).

Net income for third-quarter 2011 includes the following pre-tax items:

- $50 million write-off of leasehold costs associated with approximately 65 percent of our Columbia County, Pennsylvania acreage;
- $11 million of dry hole costs associated with an exploratory Marcellus Shale well in Columbia County.

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures
(Unaudited)

We have significant oil and gas producing activities primarily in the Rocky Mountain region, North Dakota and Pennsylvannia in the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. The following information excludes our gas management activities.

With the exception of Capitalized Costs and the Results of Operations for all years presented, the following information includes information, through the date of sale, for the holdings in the Barnett Shale and Arkoma Basin which have been reported as discontinued operations in our consolidated financial statements. These operations represented less than five percent of our total domestic and international proved reserves in 2011.

Capitalized Costs

	As of December 31, 2011			
	Domestic	International	Consolidated Total	Entity's share of international equity method investee
	(Millions)			
Proved Properties	$ 9,931	$ 259	$10,190	$ 254
Unproved properties	1,655	3	1,658	—
	11,586	262	11,848	254
Accumulated depreciation, depletion and amortization and valuation provisions	(3,678)	(133)	(3,811)	(154)
Net capitalized costs	$ 7,908	$ 129	$ 8,037	$ 100

	As of December 31, 2012			
	Domestic	International	Consolidated Total	Entity's share of international equity method investee
	(Millions)			
Proved Properties	$11,295	$ 310	$11,605	$ 292
Unproved properties	1,153	9	1,162	1
	12,448	319	12,767	293
Accumulated depreciation, depletion and amortization and valuation provisions	(4,612)	(161)	(4,773)	(181)
Net capitalized costs	$ 7,836	$ 158	$ 7,994	$ 112

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $436 million and $251 million, net, for 2012 and 2011, respectively.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs and successful exploratory wells.
- Unproved properties consist primarily of unproved leasehold costs and costs for acquired unproved reserves.

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Cost Incurred

	Domestic	International	Entity's share of international equity method investee
		(Millions)	
For the Year Ended December 31, 2010			
Acquisition	$1,731	$—	$—
Exploration	22	13	3
Development	988	27	25
	$2,741	$ 40	$ 28
For the Year Ended December 31, 2011			
Acquisition	$ 45	$—	$—
Exploration	31	20	8
Development	1,461	24	26
	$1,537	$ 44	$ 34
For the Year Ended December 31, 2012			
Acquisition	$ 111	$—	$—
Exploration	23	31	5
Development	1,130	35	35
	$1,264	$ 66	$ 40

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: The 2012 costs are primarily for undeveloped leasehold in exploratory areas targeting oil reserves. The 2011 costs are primarily for additional leasehold in the Appalachian Basin. The 2010 costs are primarily for additional leasehold in the Williston and Appalachian Basins and include approximately $422 million of proved property values.
- Exploration costs include the costs incurred for geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions and retaining undeveloped leaseholds.
- Development costs include costs incurred to gain access to and prepare well locations for drilling and to drill and equip wells in our development basins.
- We have classified our step-out drilling and site preparation costs in the Powder River Basin as development. While the immediate offsets are frequently in the dewatering stage, the development classification better reflects the low risk profile of the costs incurred.

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Results of Operations

	Domestic	International	Total
		(Millions)	
For the Year Ended December 31, 2010			
Revenues:			
Natural gas sales	$1,700	$ 15	$1,715
Oil and condensate sales	55	71	126
Natural gas liquid sales	282	3	285
Other revenues	40	—	40
Total revenues	2,077	89	2,166
Costs:			
Lease and facility operating	244	19	263
Gathering, processing and transportation	320	—	320
Taxes other than income	104	16	120
Exploration	51	6	57
Depreciation, depletion and amortization	794	17	811
Impairment of costs of acquired unproved reserves	175	—	175
Goodwill impairment	1,003	—	1,003
General and administrative	214	9	223
Other (income) expense	(18)	—	(18)
Total costs	2,887	67	2,954
Results of operations	(810)	22	(788)
Provision (benefit) for income taxes	70	8	78
Exploration and production net income (loss)	$ (880)	$ 14	$ (866)

	Domestic	International	Total
		(Millions)	
For the Year Ended December 31, 2011			
Revenues:			
Natural gas sales	$1,678	$ 16	$1,694
Oil and condensate sales	226	86	312
Natural gas liquid sales	404	4	408
Other revenues	7	4	11
Total revenues	2,315	110	2,425
Costs:			
Lease and facility operating	235	27	262
Gathering, processing and transportation	487	—	487
Taxes other than income	113	21	134
Exploration	123	3	126
Depreciation, depletion and amortization	880	22	902
Impairment of certain natural gas properties in the Powder River Basin	276	—	276
Impairment of costs of acquired unproved reserves	91	—	91
General and administrative	246	12	258
Other (income) expense	(3)	3	—
Total costs	2,448	88	2,536
Results of operations	(133)	22	(111)
Provision (benefit) for income taxes	(49)	8	(41)
Exploration and production net income (loss)	$ (84)	$ 14	$ (70)

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

	Domestic	International	Total
		(Millions)	
For the Year Ended December 31, 2012			
Revenues:			
Natural gas sales	$1,346	$ 18	$1,364
Oil and condensate sales	376	115	491
Natural gas liquid sales	296	3	299
Net gain on derivatives not designated as hedges	66	—	66
Other revenues	7	1	8
Total revenues	2,091	137	2,228
Costs:			
Lease and facility operating	251	32	283
Gathering, processing and transportation	504	2	506
Taxes other than income	87	24	111
Exploration	72	11	83
Depreciation, depletion and amortization	939	27	966
Impairment of certain natural gas properties in the Green River Basin	48	—	48
Impairment of costs of acquired unproved reserves	177	—	177
General and administrative	267	14	281
Other (income) expense	14	—	14
Total costs	2,359	110	2,469
Results of operations	(268)	27	(241)
Provision (benefit) for income taxes	(98)	10	(88)
Exploration and production net income (loss)	$ (170)	$ 17	$ (153)

- Amount for all years exclude the equity earnings from the international equity method investee. Equity earnings from this investee were $26 million, $24 million and $16 million in 2012, 2011 and 2010, respectively.
- Natural gas revenues consist of natural gas production sold and includes realized gains (losses) of derivatives that were designated as cash flow hedges.
- For derivative instruments that were entered into after January 1, 2013, we did not designate those as cash flow hedges. Any gain (loss) related to these derivatives is included in net gain on derivatives not designated as hedges.
- Other revenues consist of activities that are an indirect part of the producing activities.
- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Depreciation, depletion and amortization includes depreciation of support equipment.

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Proved Reserves

Our international reserves are primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest. The Entity's share of international equity method investee represents Apco's 40.8% interest in reserves of Petrolera Entre Lomas S.A.

	Natural Gas (Bcf)			
	Domestic	International	Entity's share of international equity method investee	Combined
Proved reserves at December 31, 2009	**4,069.7**	**84.5**	**36.1**	**4,190.3**
Revisions	(274.7)	(13.1)	2.2	(285.6)
Purchases	37.3	—	—	37.3
Extensions and discoveries	478.7	11.9	13.7	504.3
Production	(396.8)	(9.0)	(3.8)	(409.6)
Proved reserves at December 31, 2010	**3,914.2**	**74.3**	**48.2**	**4,036.7**
Revisions	(279.4)	0.2	(4.0)	(283.2)
Purchases	8.0	—	—	8.0
Divestitures	(12.8)	—	—	(12.8)
Extensions and discoveries	769.7	9.6	11.5	790.8
Production	(416.8)	(9.1)	(4.7)	(430.6)
Proved reserves at December 31, 2011	**3,982.9**	**75.0**	**51.0**	**4,108.9**
Revisions	(404.8)	(18.0)	(18.5)	(441.3)
Purchases	5.8	—	—	5.8
Divestitures	(217.0)	—	—	(217.0)
Extensions and discoveries	409.2	5.7	7.4	422.3
Production	(407.0)	(8.6)	(4.4)	(420.0)
Proved reserves at December 31, 2012	**3,369.1**	**54.1**	**35.5**	**3,458.7**
Proved developed reserves at December 31, 2010	2,368.5	43.4	27.9	2,439.8
Proved developed reserves at December 31, 2011	2,497.3	48.4	28.5	2,574.2
Proved developed reserves at December 31, 2012	2,170.7	36.5	20.8	2,228.0

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

	NGLs (MMBbls)			
	Domestic	International	Entity's share of international equity method investee	Combined
Proved reserves at December 31, 2009	**64.1**	**1.0**	**1.0**	**66.1**
Revisions	30.7	—	—	30.7
Purchases	0.2	—	—	0.2
Extensions and discoveries	8.9	0.1	0.2	9.2
Production	(8.1)	(0.1)	(0.1)	(8.3)
Proved reserves at December 31, 2010	**95.8**	**1.0**	**1.1**	**97.9**
Revisions	23.0	(0.1)	(0.1)	22.8
Purchases	0.3	—	—	0.3
Extensions and discoveries	25.0	—	—	25.0
Production	(10.1)	(0.1)	(0.1)	(10.3)
Proved reserves at December 31, 2011	**134.0**	**0.8**	**0.9**	**135.7**
Revisions	(21.1)	—	—	(21.1)
Divestitures	(1.0)	—	—	(1.0)
Extensions and discoveries	8.9	—	—	8.9
Production	(10.4)	(0.1)	(0.1)	(10.6)
Proved reserves at December 31, 2012	**110.4**	**0.7**	**0.8**	**111.9**
Proved developed reserves at December 31, 2010	**48.7**	**0.7**	**0.7**	**50.1**
Proved developed reserves at December 31, 2011	**72.1**	**0.6**	**0.6**	**73.3**
Proved developed reserves at December 31, 2012	**64.9**	**0.5**	**0.6**	**66.0**

	Oil (MMBbls)			
	Domestic	International	Entity's share of international equity method investee	Combined
Proved reserves at December 31, 2009	**4.7**	**11.1**	**13.0**	**28.8**
Revisions	(0.9)	0.1	0.3	(0.5)
Purchases	20.5	—	—	20.5
Extensions and discoveries	0.9	2.0	1.7	4.6
Production	(0.9)	(1.3)	(1.6)	(3.8)
Proved reserves at December 31, 2010	**24.3**	**11.9**	**13.4**	**49.6**
Revisions	1.2	(0.7)	(0.9)	(0.4)
Extensions and discoveries	24.3	1.5	1.3	27.1
Production	(2.7)	(1.4)	(1.6)	(5.7)
Proved reserves at December 31, 2011	**47.1**	**11.3**	**12.2**	**70.6**
Revisions	5.6	(1.1)	(1.1)	3.4
Divestitures	(0.3)	—	—	(0.3)
Extensions and discoveries	28.5	2.1	1.1	31.7
Production	(4.4)	(1.5)	(1.6)	(7.5)
Proved reserves at December 31, 2012	**76.5**	**10.8**	**10.6**	**97.9**
Proved developed reserves at December 31, 2010	**4.0**	**7.1**	**8.1**	**19.2**
Proved developed reserves at December 31, 2011	**13.6**	**6.8**	**7.6**	**28.0**
Proved developed reserves at December 31, 2012	**23.7**	**6.1**	**6.4**	**36.2**

	All products (Bcfe) (a)			
	Domestic	International	Entity's share of international equity method investee	Combined
Proved reserves at December 31, 2009	**4,481.8**	**156.9**	**120.1**	**4,758.8**
Revisions	(95.8)	(12.5)	4.0	(104.3)
Purchases	161.8	—	—	161.8
Extensions and discoveries	537.5	24.5	25.1	587.1
Production	(450.3)	(17.5)	(14.0)	(481.8)
Proved reserves at December 31, 2010	**4,635.0**	**151.4**	**135.2**	**4,921.6**
Revisions	(134.3)	(4.6)	(10.0)	(148.9)
Purchases	9.9	—	—	9.9
Divestitures	(12.8)	—	—	(12.8)
Extensions and discoveries	1,065.5	18.6	19.3	1,103.4
Production	(493.2)	(18.2)	(14.9)	(526.3)
Proved reserves at December 31, 2011	**5,070.1**	**147.2**	**129.6**	**5,346.9**
Revisions	(498.6)	(24.7)	(25.1)	(548.4)
Purchases	5.8	—	—	5.8
Divestitures	(224.8)	—	—	(224.8)
Extensions and discoveries	633.8	18.3	14.0	666.1
Production	(495.8)	(18.0)	(14.6)	(528.4)
Proved reserves at December 31, 2012	**4,490.5**	**122.8**	**103.9**	**4,717.2**
Proved developed reserves at December 31, 2010	**2,684.4**	**90.1**	**80.7**	**2,855.2**
Proved developed reserves at December 31, 2011	**3,011.5**	**93.0**	**77.7**	**3,182.2**
Proved developed reserves at December 31, 2012	**2,702.6**	**76.1**	**62.8**	**2,841.5**

(a) Oil and natural gas liquids were converted to Bcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.
- Purchases in 2010 include proved developed reserves of 42 Bcfe.
- Revisions in 2012 primarily resulted from the lower 12-month average price as compared to the 12-month average price used in 2011. Revisions in 2011 and 2010 primarily relate to the reclassification of reserves from proved to probable reserves attributable to locations not expected to be developed within five years.
- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves. Prices are based on the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. For the years ended December 31, 2012 and 2011 and 2010, the average domestic combined natural gas, oil and NGL equivalent price, including deductions for gathering, processing and transportation, used in the estimates was $3.16, $3.89 and $3.48 per Mcfe, respectively. The decrease in the equivalent price from 2011 reflects the decreases in the 12-month average commodity prices partially offset by the growth of oil as a percent of total reserves. The increase in the equivalent price in 2010 reflects the impact of oil and NGLs growth in our reserves. Future cash inflows for the year ended December 31, 2010 reflects deductions for the estimates for gathering, processing and transportation. For the years ended December 31, 2011 and 2012, the estimates for gathering, processing and transportation are included in production costs. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

As of December 31, 2011	Domestic	International(a)	Entity's share of international equity method investee(b)
		(Millions)	
Future cash inflows	$25,498	$ 897	$ 891
Less:			
Future production costs	11,738	340	336
Future development costs	3,484	126	117
Future income tax provisions	3,196	100	117
Future net cash flows	7,080	331	321
Less 10 percent annual discount for estimated timing of cash flows	(3,489)	(132)	(124)
Standardized measure of discounted future net cash inflows	$ 3,591	$ 199	$ 197

As of December 31, 2012	Domestic	International(a)	Entity's share of international equity method investee(b)
Future cash inflows	$18,435	$ 968	$ 892
Less:			
Future production costs	9,836	385	356
Future development costs	3,217	136	115
Future income tax provisions	1,059	97	104
Future net cash flows	4,323	350	317
Less 10 percent annual discount for estimated timing of cash flows	(2,374)	(136)	(118)
Standardized measure of discounted future net cash inflows	$ 1,949	$ 214	$ 199

(a) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(b) Represents Apco's 40.8% interest in Petrolera Entre Lomas S.A.

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

For the Year Ended December 31, 2010	Domestic	International(a)	Entity's share of international equity method investee(b)
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 1,713	$175	$129
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,446)	(59)	(55)
Net change in prices and production costs	1,921	34	43
Extensions, discoveries and improved recovery, less estimated future costs	724	—	—
Development costs incurred during year	633	26	25
Changes in estimated future development costs	(292)	(12)	(15)
Purchase of reserves in place, less estimated future costs	439	2	—
Revisions of previous quantity estimates	(332)	26	63
Accretion of discount	220	22	17
Net change in income taxes	(758)	(13)	(20)
Other	(8)	(3)	(1)
Net changes	1,101	23	57
Standardized measure of discounted future net cash flows end of period	$ 2,814	$198	$186

For the Year Ended December 31, 2011	Domestic	International(a)	Entity's share of international equity method investee(b)
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 2,814	$198	$186
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,194)	(64)	(61)
Net change in prices and production costs	495	26	29
Extensions, discoveries and improved recovery, less estimated future costs	1,661	—	—
Development costs incurred during year	593	23	25
Changes in estimated future development costs	(750)	(32)	(30)
Purchase of reserves in place, less estimated future costs	15	—	—
Sale of reserves in place, loss estimated future costs	(20)	—	—
Revisions of previous quantity estimates	(209)	22	18
Accretion of discount	395	25	26
Net change in income taxes	(226)	6	4
Other	17	(5)	—
Net changes	777	1	11
Standardized measure of discounted future net cash flows end of period	$ 3,591	$199	$197

WPX Energy, Inc.

Supplemental Oil and Gas Disclosures—(Concluded)
(Unaudited)

For the Year Ended December 31, 2012	Domestic	International(a)	Entity's share of international equity method investee(b)
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 3,591	$199	$197
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(778)	(78)	(78)
Net change in prices and production costs	(3,601)	46	49
Extensions, discoveries and improved recovery, less estimated future costs	1,154	—	—
Development costs incurred during year	333	35	35
Changes in estimated future development costs	50	(16)	(17)
Purchase of reserves in place, less estimated future costs	4	—	—
Sale of reserves in place, loss estimated future costs	(272)	—	—
Revisions of previous quantity estimates	(232)	(3)	(26)
Accretion of discount	481	26	27
Net change in income taxes	1,194	5	12
Other	25	—	—
Net changes	(1,642)	15	2
Standardized measure of discounted future net cash flows end of period	$ 1,949	$214	$199

(a) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(b) Represents Apco's 40.8% interest in Petrolera Entre Lomas S.A.

WPX Energy, Inc.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	Charged (Credited) to Costs and Expenses	Other	Deductions	Ending Balance
			(Millions)		
2012:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$13	$—	$—	$ (2)	$ 11
Deferred tax asset valuation allowance(a)	16	3	—	—	19
2011:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$16	$ (1)	$—	$ (2)	$ 13
Deferred tax asset valuation allowance(a)	22	—	—	(6)(d)	16
2010:					
Allowance for doubtful accounts—accounts and notes receivable(a)	19	(3)	—	—	16
Deferred tax asset valuation allowance(a)	22	—	—	—	22
Price-risk management credit reserves—liabilities(b)	(3)	3(c)	—	—	—

(a) Deducted from related assets.
(b) Deducted from related liabilities.
(c) Included in revenues.
(d) Deferred tax asset retained by Williams.

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a—15(e) and 15d—15(e) of the Securities Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth in Item 8, "Financial Statements and Supplementary Data."

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth in Item 8, "Financial Statements and Supplementary Data."

Fourth Quarter 2012 Changes in Internal Controls

There have been no changes during the fourth quarter of 2012 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information called for by this Item 10 is incorporated by reference to our definitive proxy statement for our 2013 Annual meeting of Stockholders, or our 2013 Proxy Statement, anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, under the headings "Proposal 1—Election of Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership and Reporting Compliance."

Item 11. *Executive Compensation*

The information called for by this Item 11 is incorporated by reference to our 2013 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, under the headings "Executive Compensation" and "Compensation Interlocks and Insider Participation."

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

The information called for by this Item 12 is incorporated by reference to our 2013 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, under the headings "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information."

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

The information called for by this Item 13 is incorporated by reference to our 2013 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, under the headings "Corporate Governance" and "Certain Relationships and Transactions."

Item 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated by reference to our 2013 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, under the heading "Independent Registered Public Accounting Firm."

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
3.2	Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.4	Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.5	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)
10.6#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
10.7	Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012)(1)
10.8	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012)(1)

Certain portions have been omitted pursuant to an Order Granting Confidential Treatment issued by the SEC on December 5, 2011. Omitted information has been filed separately with the SEC.

Exhibit No.	Description
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	WPX Energy, Inc. 2011 Incentive Plan (incorporated herein by reference to Exhibit 4.3 to WPX Energy, Inc.'s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011)(1)
10.11	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.'s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011)(1)
10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13*	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (1)
10.14*	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (1)
10.15*	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (1)
10.16*	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (1)
10.17*	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (1)
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP
23.2*	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase
101.DEF**	XBRL Taxonomy Extension Definition Linkbase
101.LAB**	XBRL Taxonomy Extension Label Linkbase
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

** Furnished herewith

(1) Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WPX ENERGY, Inc.
(Registrant)

By: /s/ J. Kevin Vann

J. Kevin Vann
Controller

Date: February 28, 2013

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

Signature	Title	Date
/s/ Ralph A. Hill	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2013
/s/ Rodney J. Sailor	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2013
/s/ J. Kevin Vann	Controller (Principal Accounting Officer)	February 28, 2013
/s/ Kimberly S. Bowers* *	Director	February 28, 2013
/s/ John A. Carrig* *	Director	February 28, 2013
/s/ William R. Granberry* *	Director	February 28, 2013
/s/ Don J. Gunther* *	Director	February 28, 2013
/s/ Robert K. Herdman* *	Director	February 28, 2013
/s/ Kelt Kindick* *	Director	February 28, 2013
/s/ Henry E. Lentz* *	Director	February 28, 2013
/s/ George A. Lorch* *	Director	February 28, 2013
/s/ William G. Lowrie* *	Chairman of the Board	February 28, 2013
/s/ David F. Work* *	Director	February 28, 2013
*By: /s/ Stephen E. Brilz **Attorney-in-Fact**		February 28, 2013

CORPORATE DATA

Annual Meeting
Stockholders are invited to our annual meeting at 9:30 a.m. Central Daylight Time on May 22, 2013, Williams Resource Center Theater, One Williams Center, Tulsa, Okla.

Internet
Company information is available at www.wpxenergy.com.

Inquiries
A stockholder may obtain a free copy of our 2012 Annual Report on Form 10-K, which was filed with the SEC, by contacting our investor relations group. Call David Sullivan at 539.573.9360, or 855.WPX.2012. Direct your written inquiries to investor relations at our headquarters address below.

Corporate Headquarters
One Williams Center, Tulsa, OK 74172
Phone: 855.979.2012

Washington Office
801 Pennsylvania Ave., Suite 315
Washington, DC 20004

Transfer Agent and Registrar
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
800.884.4225 or 781.575.2879
Website: www.computershare.com

Auditors
Ernst & Young LLP
Box 1529
Tulsa, OK 74101

Corporate Governance
Our Code of Business Conduct, our Code of Ethics for Senior Officers, the charters for the committees of the Board of Directors, and our Corporate Governance Guidelines are available on our website at www.wpxenergy.com.

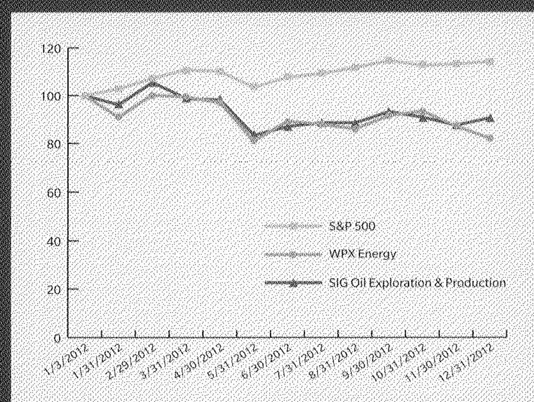
Equal Opportunity
The Company is an Equal Employment Opportunity (EEO) employer and does not discriminate in any employer/employee relations based on race, color, religion, sex, sexual orientation, national origin, age, disability or veteran's status.

STOCKHOLDER INFORMATION

WPX Energy Securities
WPX Energy common stock began trading on the New York Stock Exchange on Jan. 3, 2012, under the ticker symbol WPX.

On March 25, 2013, 8,766 stockholders of record held 200,204,041 shares of WPX Energy common stock.

WPX Energy Stock Performance
Set forth below is a line graph comparing the cumulative stockholder return of WPX Energy's common stock against the cumulative total return of each of the Standard and Poor's 500 Stock Index and the SIG Oil Exploration and Production Index. The graph assumes that $100 was invested on Jan. 3, 2012, the first day WPX Energy common stock was traded, in each of WPX Energy's common stock, the Standard and Poor's 500 Stock Index and the SIG Oil Exploration and Production Index, and that all dividends were reinvested.



WPX Energy Common Stock Sales Prices ($/share)

	Market Price	
Year ended Dec. 31, 2012	High	Low
1st Quarter	19.74	14.20
2nd Quarter	18.90	13.22
3rd Quarter	17.73	14.15
4th Quarter	18.31	14.43

Members of WPX Energy's management rang the opening bell at the New York Stock Exchange on Jan. 3, 2012, the company's first day of regular trading.

WPXENERGY®

www.wpxenergy.com