APACHE CORP
Form 10-K
March 01, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] 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 1-4300

APACHE CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**41-0747868**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400

(Address of principal executive offices)

Registrant s telephone number, including area code **(713) 296-6000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	New York Stock Exchange, Chicago Stock Exchange and NASDAQ National Market
Preferred Stock Purchase Rights	New York Stock Exchange and Chicago Stock Exchange
Apache Finance Canada Corporation 7.75% Notes Due 2029 Irrevocably and Unconditionally	New York Stock Exchange

Guaranteed by Apache Corporation	
Depositary Shares Representing a 1/20th Interest in a Share of 6.00% Mandatory Convertible Preferred Stock, Series D	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.625 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] 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 [X]

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 [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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 [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes [ ] No [X]

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2012	$ 34,382,410,237
Number of shares of registrant s common stock outstanding as of January 31, 2013	391,758,883

Documents Incorporated By Reference

Portions of registrant s proxy statement relating to registrant s 2013 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

3-D means three-dimensional.

4-D means four-dimensional.

b/d means barrels of oil or natural gas liquids per day.

bbl or bbls means barrel or barrels of oil.

bcf means billion cubic feet.

boe means barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.

boe/d means boe per day.

Btu means a British thermal unit, a measure of heating value.

LIBOR means London Interbank Offered Rate.

LNG means liquefied natural gas.

Mb/d means Mbbls per day.

Mbbls means thousand barrels of oil.

Mboe means thousand boe.

Mboe/d means Mboe per day.

Mcf means thousand cubic feet of natural gas.

Mcf/d means Mcf per day.

MMbbls means million barrels of oil.

MMboe means million boe.

MMBtu means million Btu.

MMBtu/d means MMBtu per day.

MMcf means million cubic feet of natural gas.

MMcf/d means MMcf per day.

NGL or NGLs means natural gas liquids, which are expressed in barrels.

NYMEX means New York Mercantile Exchange.

oil includes crude oil and condensate.

PUD means proved undeveloped.

SEC means United States Securities and Exchange Commission.

Tcf means trillion cubic feet.

U.K. means United Kingdom.

U.S. means United States.

With respect to information relating to our working interest in wells or acreage, net oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEMS 1 AND 2. ***BUSINESS AND PROPERTIES***

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk Forward-Looking Statements and Risk of this Form 10-K.

General

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. We currently have exploration and production interests in six countries: the U.S., Canada, Egypt, Australia, the U.K. North Sea (North Sea), and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities. We treat all operations as one line of business.

Our common stock, par value $0.625 per share, has been listed on the New York Stock Exchange (NYSE) since 1969, on the Chicago Stock Exchange (CHX) since 1960, and on the NASDAQ National Market (NASDAQ) since 2004. On June 7, 2012, we filed certifications of our compliance with the listing standards of the NYSE and the NASDAQ, including our principal executive officer s certification of compliance with the NYSE standards. Through our website, www.apachecorp.com, you can access, free of charge, electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance (including our Code of Business Conduct and Governance Principles), and documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. Included in our annual and quarterly reports are the certifications of our principal executive officer and our principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. You may also request printed copies of our committee charters or other governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Our reports filed with the SEC are made available to read and copy at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov. From time to time, we also post announcements, updates, and investor information on our website in addition to copies of all recent press releases. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Properties to which we refer in this document may be held by subsidiaries of Apache Corporation. References to Apache or the Company include Apache Corporation and its consolidated subsidiaries unless otherwise specifically stated.

Growth Strategy

Apache s mission is to grow a profitable global exploration and production company in a safe and environmentally responsible manner for the long-term benefit of our shareholders. Apache s long-term perspective has many dimensions, which are centered on the following core strategic components:

- balanced portfolio of core assets
- conservative capital structure
- rate of return focus

Throughout the cycles of our industry, these strategies have underpinned our ability to deliver long-term production and reserve growth and achieve competitive returns on invested capital for the benefit of our shareholders. We have increased reserves 23 out of the last 27 years and production 32 out of the past 34 years, a testament to our consistency over the long-term.

Apache pursues opportunities for growth through exploration and development drilling, supplemented by occasional strategic acquisitions. After a three-year period of significant portfolio expansion through acquisitions, we have shifted our focus back to developing our enlarged property base. In 2012, we generated approximately $8.5 billion of cash flows from operating activities, which enabled us to have an active drilling and development program across all of our regions. As a result, we reported record production of 779 Mboe/d, up over four percent from the prior year. At the same time, we have also invested a larger portion of our capital budget on long-lead time projects than we have in the past. In 2012, we spent approximately one-quarter of our capital budget on purchasing additional leasehold acreage, obtaining seismic data, building infrastructure, and proceeding on long-lead development projects including LNG facilities. Coupled with an active drilling program and our new venture exploration efforts, these longer-term investments secure a platform for future profitable growth.

While we are focused on growth through the drill bit, we also seek acquisition opportunities that meet our criteria for risk, reward, rate of return, and growth potential. From April 2010 through the end of 2012, Apache announced several significant acquisitions, each of which fit well with our long-term growth strategy. These properties are strategically positioned with our existing infrastructure and play to the strengths that come with our operating experience. Our significant acquisitions and other transactions since 2010 are described below.

2012 Transactions

Chevron Kitimat transaction On December 24, 2012, Chevron Canada Limited (Chevron Canada) and Apache Canada Ltd. (Apache Canada) entered into an agreement to build and operate the Kitimat LNG project. Pursuant to the agreement, each will become a 50-percent owner of the proposed Kitimat LNG plant, the Pacific Trail Pipeline, and 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant, which will be located on the northern British Columbia coast, and the pipeline; Apache Canada will operate Horn River and Liard. The transaction closed on February 8, 2013.

Central Anadarko basin acquisition In April 2012 Apache completed the acquisition of Cordillera Energy Partners III, LLC (Cordillera), a privately held company, for $2.7 billion in cash and approximately 6.3 million shares of Apache common stock.

Yara Pilbara Holdings Pty Limited acquisition On January 31, 2012, a subsidiary of Apache Energy Limited completed the acquisition of a 49-percent interest in Yara Pilbara Holdings Pty Limited (YPHPL, formerly Burrup Holdings Limited) for $439 million, including working capital adjustments. YPHPL is the owner of an ammonia fertilizer plant on the Burrup Peninsula of Western Australia.

2011 Transactions

North Sea acquisition On December 30, 2011, Apache completed the acquisition of Mobil North Sea Limited (Mobil North Sea) from Exxon Mobil Corporation with cash consideration of $1.25 billion.

2010 Transactions

Gulf of Mexico Shelf acquisition On June 9, 2010, Apache completed the acquisition of oil and gas assets in the Gulf of Mexico shelf from Devon Energy Corporation for $1.05 billion.

Permian acquisition On August 10, 2010, we completed the acquisition of BP plc s (BP) oil and gas operations, acreage, and infrastructure in the Permian Basin for $2.5 billion, net of preferential rights to purchase.

Canadian acquisition On October 8, 2010, we completed the acquisition of substantially all of BP s upstream natural gas business in western Alberta and British Columbia for $3.25 billion.

Egyptian acquisition On November 4, 2010, we completed the acquisition of BP s assets in Egypt s Western Desert for $650 million.

Mariner merger On November 10, 2010, Apache completed the acquisition of Mariner Energy, Inc. (Mariner) for stock and cash consideration totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt with the merger.

For a more in-depth discussion of our growth strategy, 2012 results, and the Company s capital resources and liquidity, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Geographic Area Overviews

We currently have exploration and production interests in six countries: the U.S., Canada, Egypt, Australia, the U.K. North Sea, and Argentina. Apache also pursues exploration interests in other countries that may over time result in reportable discoveries and development opportunities.

The following table sets out a brief comparative summary of certain key 2012 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2012 Production (In MMboe)	Percentage of Total 2012 Production	2012 Production Revenue (In millions)	12/31/12 Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	2012 Gross Wells Drilled	2012 Gross Productive Wells Drilled
United States	113.5	40%	$ 6,226	1,424	50%	1,052	1,035
Canada	44.7	16	1,322	541	19	169	145
Total North America	158.2	56	7,548	1,965	69	1,221	1,180
Egypt	58.1	20	4,554	273	10	198	174
Australia	23.6	8	1,575	342	12	15	8
North Sea	27.4	10	2,751	170	6	21	16
Argentina	17.7	6	519	102	3	30	30
Other International						1	
Total International	126.8	44	9,399	887	31	265	228
Total	285.0	100%	$ 16,947	2,852	100%	1,486	1,408

North America

Apache s North American asset base primarily comprises operations in the central U.S., the Permian Basin, the Gulf Coast onshore and offshore areas of the U.S., and operations in Western Canada. In 2012, our North America assets contributed 56 percent of our production and 45 percent of our oil and gas production revenues. At year-end 2012, 69 percent of our estimated proved reserves were located in North America.

United States

Overview We have 12.3 million gross acres across the U.S., approximately 60 percent of which is undeveloped. After expanding our portfolio over the last three years, we now hold leading positions in many attractive basins and plays within the United States. To focus our development efforts in the U.S., we have divided our assets into five distinct regions: Central, Permian, Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore. We also have leasehold acreage holdings in Alaska and other states where we are pursuing exploration opportunities. Our holdings in the U.S. provide a balance of hydrocarbon mix and reserve life and an opportunity for continued exploration. In 2012, 54 percent of our U.S. production and 63 percent of our U.S. year-end estimated proved reserves were oil and liquids. In addition, the reserve life of our U.S. regions ranged from 6 to 20 years with the Gulf of Mexico offshore region s shorter-lived reserves balancing longer-lived reserves in the Central and Permian regions. In 2012, 40 percent of Apache s equivalent production and 50 percent of Apache s total year-end estimated proved reserves were in the U.S.

Central Region The Central region includes more than 3,500 producing wells primarily in western Oklahoma and the Texas panhandle and controls nearly 1.9 million gross acres. The region is Apache s first core area dating back over half a century and has historically grown through low-risk, highly predictable natural gas exploitation. Over the last three years, however, a transformation from vertical to horizontal drilling and continued price disparity between crude oil and natural gas have evolved the region from one targeting natural gas to one now targeting oil and liquids-rich gas plays. This focus resulted in liquids production growth of over 115 percent during 2011. Oil and liquids production further expanded during 2012, with oil production more than doubling and NGL production almost tripling compared to the prior year. Total region production was up 37 percent in 2012. The Central region contributed 8 percent of Apache s 2012 equivalent production and 9 percent of total year-end proved reserves.

The primary driver of the region s growth was an active exploration and development program where we drilled or participated in drilling 192 wells during 2012, 99 percent of which were completed as producers. A significant focus of our drilling program has been in the Anadarko basin s Granite Wash play. The Granite Wash consists of a series of thick, multi-layered formations of low-permeability and liquids-rich sandstones. The Company s significant acreage position in the play has generated an active drilling plan for the next several years across numerous formations, notably the Tonkawa, Marmaton, Cottage Grove, and Cleveland.

We have also been drilling Canyon Wash wells on approximately 92,000 net acres in the Whittenburg basin. During the year, we drilled and completed seven successful wells in the Canyon Wash, which averaged 30-day gross rates of approximately 675 b/d and 500 Mcf/d. These tests are an encouraging validation of this play, given the results are from vertically drilled wells.

Our drilling momentum in the Central region was further bolstered in April when the Company completed the acquisition of Cordillera, a privately held company with approximately 312,000 net acres in the heart of the Anadarko basin, nearly 18 Mboe/d of production, and estimated proved reserves of 70 MMboe. The acquisition doubled Apache s acreage in the Granite Wash area and added a robust drilling inventory that was immediately integrated into our existing program.

The region operated an average of 18 drilling rigs during 2012 and, with a growing portfolio of drilling opportunities, plans to run an average of 29 rigs during 2013. We expect to invest approximately $1.4 billion in 2013 for drilling, recompletions, equipment upgrades, and production enhancement projects. The region will also invest in facility and transportation projects to increase takeaway capacity.

Permian Region Our Permian region controls over 3.5 million gross acres with exposure across every major play in the Permian Basin. The region s property and acreage base has increased substantially over the last three years through an active acquisition effort. Apache is now one of the largest operators in the Permian Basin, operating more than 12,000 wells in 152 fields, including 47 waterfloods and 7 active CO2 floods, including the Roberts Unit, which initiated CO2 injection in January 2013. In 2012, liquids production in the region was up 25 percent, contributing to a total sequential production increase of over 18 percent as a result of an active drilling program that is continuing to ramp up. We averaged running 32 rigs during the year, drilling or participating in 781 wells, and plan to run 34 rigs in 2013. The Permian region s year-end 2012 estimated proved reserves were 800 MMboe and represented 28 percent of Apache s total proved reserves.

A key focus area of our activity during the year continued to be the multi-zone development of the Deadwood area. Deadwood is the most active of our plays in the Midland basin, where we ran an average of

16 rigs and drilled 317 wells. Specifically, the region is primarily drilling vertical wells targeting the Wolfwood and the Fusselman zones. With additional 3-D seismic data recently acquired, our ability to target other prolific accumulations and new drilling locations has been enhanced.

The region is also building a large inventory of horizontal drilling opportunities based on success achieved over 2012, having drilled or participated in drilling 104 horizontal wells during the period. Two horizontal plays in the Midland Basin, the Wolfcamp and Cline shales, have been drilled and commercialized with multi-rig development programs moving forward. Also in the Midland Basin, we recently drilled and completed oil-producing wells in the Barnett and Deadwood shales focusing on the future potential across our large acreage position. New horizontal plays in the Mississippian Lime and Clearfork shales are planned for 2013. We recently commenced horizontal well programs in the Yeso area of New Mexico as well as in the Bone Spring and Wolfcamp plays in Texas. We also continue to achieve positive results in the Central basin with horizontal redevelopment of historically conventional fields and reservoirs. We expect to conduct greater horizontal drilling into 2013, when we project that nearly half of our rigs will be drilling horizontal wells by year-end.

Our active drilling program has resulted in production growth for the past eight sequential quarters, rising 37 percent over the past two years. Given a current inventory of over 34,000 locations, the region has a deep portfolio of drilling opportunities for multiple years. For 2013, the Permian region plans to invest approximately $2.4 billion in drilling, recompletion projects, equipment upgrades, expansion of existing facilities and equipment, and leasing activities.

Gulf Coast Regions Our Gulf Coast assets are primarily located in and along the Gulf of Mexico, in the areas onshore and offshore Texas, Louisiana, Alabama, and Mississippi. The area is divided into three regions, which include the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore.

In water depths less than 500 feet, which constitutes most of our Gulf of Mexico Shelf region, Apache is currently the largest producer and has been the largest offshore held-by-production acreage owner since 2004, holding approximately three million gross acres. The region contributed 12 percent of our worldwide production and revenue during 2012. With prolific wells, strong cash flows, and a strategic position near the petrochemical-industrial complex on the U.S. Gulf Coast, the region has consistently generated high rates of return. During 2012 the region drilled or participated in 36 wells with an 80-percent success rate, consistent with activity levels of the prior two years. In June 2012, the region also participated in the federal lease sale where we were awarded 60 blocks, opening up additional exploration and development opportunities.

In water depths greater than 500 feet, the Gulf of Mexico Deepwater region is a relatively underexplored and oil prone area that provides exposure to significant reserve and production potential. Apache s strategic presence in the area was gained through the 2010 Mariner merger and was extended through our participation in the June 2012 federal lease sale where we were awarded 28 new leases. The Company now owns approximately 900,000 gross acres across 166 blocks as of the end of 2012. The Deepwater region contributed only 2 percent of Apache s worldwide production in 2012; however, there are several large projects and developments underway that could spur significant growth. The non-operated Lucius project, where Apache holds an 11.7-percent working interest, is currently under development with first production projected for 2014. In addition, the large-scale non-operated Heidelberg project continues to move forward. Apache has a 12.5-percent working interest in this development with first production projected for 2016. The region also continues to increase its exploration activity. After drilling two wells in 2011, we drilled five wells in 2012 with a 60-percent success rate. Seven wells are planned for drilling in the areas in which we hold an interest during 2013.

Apache s Gulf Coast Onshore region includes mature onshore and near-shore basins of Texas, Louisiana, and Mississippi, where it has a significant acreage position of approximately 1.4 million gross acres, including 330,000 mineral fee acres. With advancements in modern seismic imaging, horizontal drilling and completion technologies, additional opportunities continue to evolve. During the year, the region focused on drilling shallow and moderate-depth targets, increasing acreage holdings, and expanding regional 3-D seismic databases. In addition, the region continued evaluating several unconventional resource plays and deeper exploitation opportunities. The region drilled or participated in drilling 35 wells during 2012 and plans to drill or participate in approximately 39 wells in 2013.

In 2013, Apache plans to invest approximately $700 million, $400 million, and $250 million in the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore regions, respectively. The capital will be spent on drilling, recompletion and development projects, equipment upgrades, production enhancement projects, and seismic and lease activities. The Company spent $435 million on abandonment activities in 2012 over the entire Gulf Coast area and expects similar activity levels in 2013.

U.S. Marketing In general, most of our U.S. gas is sold at either monthly or daily market prices. Our natural gas is sold primarily to local distribution companies (LDCs), utilities, end-users, and integrated major oil companies. We maintain a diverse customer portfolio, which is intended to reduce the concentration of credit risk.

Apache primarily markets its U.S. crude oil to integrated major oil companies, marketing and transportation companies, and refiners. Our objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices.

Apache s NGL production is sold under contracts with prices based on market indices, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Canada

Overview Since entering the Canadian market in 1995, Apache has continued to increase its presence in the region and now holds approximately seven million gross acres across the provinces of British Columbia, Alberta, and Saskatchewan. The region s large acreage position provides portfolio diversification as well as significant drilling opportunity. Canada represented approximately 19 percent of Apache s worldwide proved reserves at year-end 2012 and approximately 16 percent of 2012 worldwide production.

In 2012, Apache drilled or participated in drilling 169 wells in Canada, with a continued focus on increasing oil and liquids-rich gas production. Reservoir modeling and state-of-the-art horizontal drilling technology advanced several oil plays in the Viking, Glauconite, Dunvegan, and Sparky formations, and success with multi-stage fracture completions continues to increase the scope of oil and liquids-rich gas drilling opportunities.

Future natural gas drilling activity will be driven by market prices and the Kitimat LNG project. In December 2012, Apache announced an agreement with Chevron Canada to build and operate the Kitimat LNG project and develop shale gas resources at the Liard and Horn River basins in British Columbia. Chevron Canada and Apache Canada will each hold a 50-percent interest in the Kitimat LNG plant, the Pacific Trail Pipeline, and approximately 644,000 gross undeveloped acres in the Horn River and Liard basins. Chevron Canada will operate the LNG plant and pipeline, and Apache Canada will operate Horn River and Liard. The Kitimat plant has received all significant environmental approvals and a 20-year export license from the Canadian federal government. Although the project has not reached a final investment decision, we believe Chevron s experience in developing LNG projects and marketing expertise will assist in moving the development forward. The transaction was completed on February 8, 2013.

In 2013, the region plans to invest approximately $680 million in drilling and development projects, equipment upgrades, production enhancement projects, seismic acquisition, and Kitimat project development. Drilling in 2013 will continue to focus on conventional oil and liquids-rich gas plays.

Marketing Our Canadian natural gas marketing activities focus on sales to utilities, end-users, integrated major oil companies, supply aggregators, and marketers. We maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk in our portfolio. To diversify our market exposure, we transport natural gas via firm transportation contracts to export border points for delivery into Washington, California, and the Chicago area. We sell the majority of our Canadian gas on a monthly basis at either first-of-the-month or daily AECO index prices.

Canadian crude oil production is sold to integrated major companies, refiners, and marketing companies based on a WTI price, adjusted for quality, transportation, and a market-reflective negotiated differential. We maximize the value of our condensate and heavier crudes by determining whether to blend the condensate into our own crude production or sell it in the market as a segregated product. The crude is transported on pipeline or truck within Western Canada to the market hubs in Alberta and Manitoba where it is sold, allowing for a more diversified group of purchasers and a higher netback price.

The region s NGL production is sold under contracts with prices based on market indices, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

International

Apache s international assets are located in Egypt, Australia, offshore the U.K. in the North Sea, and Argentina. In 2012, international assets contributed 44 percent of our production and 55 percent of our oil and gas revenues. At year-end 2012, 31 percent of our estimated proved reserves were located outside North America.

Egypt

Overview Our activity in Egypt began in 1994 with our first Qarun discovery well. Today we control 9.7 million gross acres, making Apache the largest acreage holder in Egypt s Western Desert. Only 18 percent of our gross acreage in Egypt has been developed, with gross production of 213 Mb/d and 900 MMcf/d in 2012, or 100 Mb/d and 354 MMcf/d net to Apache. The remaining 82 percent of our acreage is undeveloped, providing us with considerable exploration and development opportunities for the future. In 2012, the region contributed 27 percent of Apache s worldwide production revenue, 20 percent of our worldwide production, and 10 percent of our year-end 2012 estimated proved reserves. Our estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country share reserves.

Our operations in Egypt are conducted pursuant to production-sharing agreements in 23 separate concessions, under which the contractor partner pays all operating and capital expenditure costs for exploration and development. Development leases within concessions generally have a 25-year life, with extensions possible for additional commercial discoveries or on a negotiated basis, and currently have expiration dates ranging from five to 25 years. A percentage of the production on development leases, usually up to 40 percent, is available to the contractor partners to recover operating and capital expenditure costs, with the balance generally allocated between the contractor partners and Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis.

Historically, growth in Egypt has been driven by an ongoing drilling program, and we are one of the most active drillers in the region. Throughout 2012, we averaged running 25 rigs and drilled 188 development and injection wells and 51 exploration wells. Approximately 55 percent of our exploration wells were successful, further expanding our presence in the westernmost concessions and unlocking additional opportunities in existing plays. A key component of the region s success has been our ability to acquire and evaluate 3-D seismic surveys that enable the region s technical teams to consistently high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic reservoirs.

Heading into 2013, the region will continue an active drilling program and plans to invest approximately $1.1 billion for drilling, recompletion projects, development projects, and seismic acquisition. There are also several key infrastructure projects underway that will focus on maintaining gas deliverability and bringing additional liquids to market.

Marketing Our gas production is sold to EGPC primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content. Apache previously agreed to accept the industry-pricing formula on a majority of gas sold but retained the previous gas-price formula (without an oil price cap) until the end of 2012 for up to 100 MMcf/d gross. The region averaged $3.90 per Mcf in 2012.

Oil from the Khalda Concession, the Qarun Concession, and other nearby Western Desert blocks is sold to third parties in the Mediterranean market or to EGPC when called upon to supply domestic demand. Oil sales are exported from or sold at one of two terminals on the northern coast of Egypt. Oil production that is presently sold to EGPC is sold on a spot basis priced at Brent with a monthly EGPC official differential applied.

Egypt political unrest In February 2011, former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power, announcing that it would remain in power until the presidential and parliamentary elections could be held. In June 2012, Mohamed Morsi of the Muslim Brotherhood s Freedom and Justice Party was elected as Egypt s new president. In December 2012 the people of Egypt ratified a new constitution. Under the new constitution, the government must hold elections for the lower house of parliament within 60 days. Apache s operations, located in remote locations in the Western Desert, have not experienced production interruptions, and we have continued to receive development lease approvals for our drilling program. However, a deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, expropriation of our assets or resource nationalization, and/or forced renegotiation or modification of our existing contracts with EGPC could materially and adversely affect our business, financial condition, and results of operations.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and other highly rated international insurers covering a portion of its investments in Egypt. In the aggregate, these insurance policies, subject to the policy terms and conditions, provide approximately $1 billion of coverage to Apache for losses arising from confiscation, nationalization, and expropriation risks, with a $263 million sub-limit for currency inconvertibility.

In addition, the Company has a separate policy with OPIC, which provides $300 million of coverage for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent Apache from exporting our share of production. In October 2012, the Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, announced that it was providing $150 million in reinsurance to OPIC for the remainder of the policy term. This provision of long-term reinsurance to OPIC will allow Apache to maintain the $300 million of insurance coverage through 2024.

Australia

Overview Apache s holdings in Australia are focused offshore Western Australia in the Carnarvon, Exmouth, and Browse basins. We have operated in the Carnarvon basin since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993. Production operations are located in the Carnarvon and Exmouth basins. In total, we control approximately 7.9 million gross acres offshore Western Australia through 30 exploration permits, 17 production licenses, and 13 retention leases. Approximately 90 percent of our acreage is undeveloped, and the region continues to actively pursue additional acreage opportunities.

During 2012, the region had net production of 29 Mb/d of oil and 214 MMcf/d of natural gas, contributing 9 percent of Apache s worldwide production revenue, 8 percent of worldwide production and 12 percent of year-end estimated proved reserves. Production compared to the prior year was 7 percent lower primarily as a result of natural decline in the Pyrenees and Van Gogh oil fields. Offsetting production declines was a full year of production from the Reindeer field. This gas is processed through the Devil Creek Gas Plant, which came online in December 2011. This plant is Western Australia s third domestic natural gas processing hub and the first new hub to be constructed in more than 15 years. Gas from the development has been sold to a number of customers in Western Australia s growing mining and minerals processing sectors at prices significantly higher than prior year realizations.

The region is a key component of Apache s exploration program. During 2012, we participated in drilling 15 offshore wells, of which 10 were exploration or appraisal wells. This compares to nine wells drilled in 2011. Over the past decade, the region s exploration activity has established a significant pipeline of projects that are expected to contribute to production growth as they are brought onstream in the coming years.

First production is projected in 2013 from four completed gas wells in the Macedon gas field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant being built at Ashburton North in Western Australia. Apache has successfully marketed nearly all of its proved reserves in the Macedon field under long-term contracts at prices significantly higher than current realizations. We have a 29-percent non-operating working interest in the field and gas plant.

Development of the Coniston oil field project, which lies just north of the Van Gogh field, continued toward projected first production in 2014. The field will be produced via subsea completions tied back to the Floating Production Storage and Offloading Vessel (FPSO) at Van Gogh. To more effectively control the Van Gogh and Coniston field operations, development, and maintenance efforts, this FPSO (the Ningaloo Vision) was purchased from the lessor in January 2012. To accommodate production from Coniston, the FPSO is scheduled to go offline to the shipyard in early 2014 to complete required modifications.

The region will also continue development of the offshore Balnaves field, an oil accumulation located near the Brunello gas field offshore Western Australia. The project is expected to deliver initial gross production of 30 Mb/d in 2014 utilizing a leased FPSO vessel. Apache has a 65-percent working interest in the project.

Further advances were made on the region s largest development effort, which is the Chevron-operated Wheatstone LNG project (Wheatstone) in Western Australia. The first phase of the Wheatstone project will comprise two LNG processing trains with a combined capacity of approximately 8.9 million metric tons per annum (mtpa), a domestic gas plant, and associated infrastructure. Apache has a 13-percent interest in the project and expects to invest approximately $4 billion over five years for the field and LNG facility development. Apache will supply gas to Wheatstone from its operated Julimar and Brunello complex. The 65-percent interest Julimar development project is expected to generate average net sales to Apache of approximately 140 MMcf/d of gas (equivalent to 1.07 million mtpa of LNG) at prices pegged to world oil markets, 22 MMcf/d of sales gas into the domestic market, and 3,250 barrels of condensate per day. First production is projected for the end of 2016.

These development projects require significant capital investments above those for traditional drilling programs. During 2013, the region plans to invest approximately $1.9 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition. Approximately $1.5 billion of our 2013 capital will be invested in long-lead development projects.

Marketing Western Australia has historically had a local market for natural gas with a limited number of buyers and sellers resulting in sales under mostly long-term, fixed-price contracts, many of which contain periodic price revision clauses based on either the Australian consumer price index or a commodity linkage. As of December 31, 2012, Apache had 21 active gas contracts in Australia with expiration dates ranging from

July 2014 to December 2026. Recent increases in demand and higher development costs have increased the prices required from the local market in order to support the development of new supplies. As a result, market prices negotiated on recent contracts are substantially higher than historical levels.

We directly market all of our Australian crude oil production into Australian domestic and international markets at prices generally indexed to Dated Brent benchmark crude oil prices plus premiums, which typically result in sales well above crude sold at West Texas Intermediate (WTI)-based prices.

During 2011, advances were made on Wheatstone, with binding Sales and Purchase Agreements signed by two Asian customers for the delivery of approximately 60 percent of Apache s net LNG offtake. In 2012, further advances were made on the Wheatstone project with the signing of two non-binding Heads of Agreements, which will take the total committed delivery volumes to over 80 percent once the final binding Sales and Purchase Agreements are signed. These binding Sales and Purchase Agreements are expected to be finalized and signed in 2013.

North Sea

Overview Apache entered the North Sea in 2003 after acquiring an approximate 97-percent working interest in the Forties field (Forties). Since acquiring Forties, Apache has actively invested in the region, having produced and sold oil volumes in excess of the proved reserves initially recorded. This success spurred last year s Mobil North Sea Limited (Mobil North Sea) acquisition, which provided the region with additional exploration and development opportunities across numerous fields, including operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields and non-operated interests in the Maclure, Scott, and Telford fields. During 2012, we also announced that the U.K. Department of Energy & Climate Change awarded the region 11 new operated licenses and 1 non-operated license, which together added approximately 613,000 gross acres to the region s portfolio. Included in these licenses is all of the available acreage adjacent to the Beryl field plus two key licenses near the Forties field.

In 2012, the North Sea region produced 64 Mb/d of oil and 57 MMcf/d of natural gas, contributing 16 percent of Apache s worldwide production revenue, 10 percent of worldwide production and 6 percent of year-end estimated proved reserves. The region s production was 36 percent higher compared to the prior year on production from the recently acquired Beryl assets and an active drilling program in both the Forties and Beryl fields. Drilling in the Forties field continued to benefit from extensive 4-D seismic interpretations obtained over the last two years and has targeted many areas of bypassed oil in the mature reservoir. A 3-D seismic survey of the Beryl field commenced in early August and, when completed, will further refine our drilling plans for these acquired assets. In 2012, 21 wells were drilled in the North Sea, of which 16 were productive. Two of the highest producing wells were the Beryl B72 well, which commenced production in May at a rate of 11.6 Mb/d and 13.1 MMcf/d, and the Beryl B73 well, which was completed in September with an initial rate of 8.2 Mb/d and 5.9 MMcf/d. Apache has a 55-percent net interest in the Beryl field as of year-end.

The region also made notable progress in several key development projects during the year. In April, production from the first Bacchus field well commenced at a peak rate of 6 Mb/d; in July, a second horizontal well was brought online at a peak rate of 9 Mb/d. Combined production from the two wells has been steady at 10 Mb/d since July. Apache s net interest is 50 percent. In September, the jacket for the Forties Alpha Satellite Platform was installed, with a topside and bridge scheduled to be delivered during the second quarter of 2013. This platform has been constructed to continue to exploit new opportunities at Forties and sits adjacent to the main Alpha platform. It will provide an additional 18 drilling slots beginning in the third quarter of 2013 along with power generation, fluid separation, gas lift compression, and oil export pumping.

In 2013, the region plans to invest approximately $900 million on a diverse set of capital projects. The region will continue to refine drilling programs associated with properties acquired in the Mobil North Sea acquisition and integrate the additional opportunities gained over the last year.

Marketing We have traditionally sold our North Sea crude oil under both term contracts and spot cargoes. The term sales are composed of a market-based index price plus a premium, which reflects the higher market value for term arrangements. The prices received for spot cargoes are market driven and can trade at a premium or discount to the market-based index.

Natural gas from the Beryl field is processed through the SAGE gas plant operated by Apache. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The condensate mix from the SAGE plant is processed further downstream. The split streams of propane and butane are sold on a monthly entitlement basis, and condensate is sold on a spot basis at the Braefoot Bay terminal using index pricing less transportation.

Argentina

Overview We have had a continuous presence in Argentina since 2001 and have grown our holdings in the region through an active drilling program and targeted acquisitions. The region currently has active operations in the provinces of Neuquén, Rio Negro, and Tierra del Fuego. We have interests in 32 concessions, exploration permits, and other interests totaling 4.4 million gross acres in four of the main Argentine hydrocarbon basins: Neuquén, Austral, Cuyo, and Noroeste. Our concessions have varying expiration dates ranging from two years to over 15 years remaining, subject to potential extensions. Apache is currently in the process of extending our concessions in the Tierra del Fuego and Rio Negro Provinces, which are scheduled to expire between 2015 and 2017. Future investment by Apache in the Tierra del Fuego and Rio Negro Provinces will be significantly influenced by the ability to extend the present concessions.

In 2012, Argentina produced 6 percent of our worldwide production and held 4 percent of our estimated proved reserves at year-end. We continue to focus our exploration and development activities in the Neuquén basin. During the year, the region drilled or participated in drilling 28 gross wells pursuant to a development drilling program that achieved a 100-percent success rate by focusing on unconventional Gas Plus gas and shallow oil plays. Our 2012 exploration program included drilling two gross horizontal wells targeting the Vaca Muerta shale formation, where we hold 1.3 million net acres, of which 586,000 net acres are in the oil play. In 2013, the region plans to finish testing and evaluating those wells in preparation for future drilling programs.

During 2013, the region plans to invest approximately $200 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

Marketing

Natural Gas Apache sells its natural gas in Argentina through three pricing structures:

Gas Plus program: This program was instituted by the Argentine government in 2008 to encourage new gas supplies through the development of conventional and unconventional (tight sands) reserves. Under this program, Apache is allowed to sell gas from qualifying projects at prices that are above the regulated rates. During 2012, the average Gas Plus volume sold by Apache was 73.2 MMcf/d at an average price of $4.89 per Mcf. For 2013, Apache has signed contracts for total gross volumes to be sold under Gas Plus contracts of 80 MMcf/d at $5.01.

Government-regulated pricing: The volumes we are required to sell at regulated prices are set by the Argentine government and vary based on seasonal factors and industry category. During 2012, we realized an average price of $0.84 per Mcf on government-regulated sales.

Unregulated market: The majority of our remaining volumes are sold into the unregulated market. In 2012, realizations on sales in the unregulated market averaged $3.52 per Mcf.

The weighted average of government-regulated and unregulated sales for 2012 was $2.03 per Mcf.

Crude Oil Our crude oil is subject to an export tax, which effectively limits the prices buyers are willing to pay for domestic sales. Domestic oil prices are currently based on $42 per barrel, plus quality adjustments and local premiums, and producers realize a gradual increase or decrease as market prices deviate from the base price.

Other Exploration

New Ventures

Apache s global New Ventures team provides exposure to new growth opportunities by looking outside of the Company s traditional core areas and targeting higher-risk, high-reward exploration opportunities located in frontier basins as well as new plays in more mature basins. The New Ventures group was established in 2010 with a worldwide program focused on deepwater exploration, where many of the world s large oil discoveries have occurred over the last decade, unconventional resources in North America and elsewhere, and underexplored basins that can be developed through application of new technologies.

Apache s 2012 activities included drilling in offshore Kenya; participating in the Suriname bid round and winning offshore block 53; establishing a presence in several known U.S. resource plays; and acquiring seismic and spudding our first well on our acreage in the Cook Inlet of Alaska. Apache s first exploration well in Kenya, the Mbawa 1, was drilled in the third quarter of 2012, encountering approximately 170 feet of natural gas pay in three zones. We have a 50-percent interest in the block and continue to analyze the well data to determine future exploration activities. In Alaska, the New Ventures team has acquired approximately 700,000 net acres over the last two years in the Cook Inlet basin and has commenced a robust seismic study over the area to facilitate future drilling activity. Apache has also leased nearly 500,000 net acres in the Mississippian Lime play in Kansas and Nebraska and 300,000 net acres in Montana s Williston basin. We have commenced drilling activity in both of these plays.

During 2013, we plan to invest approximately $100 million to further these projects and continue pursuing additional exploration opportunities.

Major Customers

In 2012, 2011, and 2010 purchases by Royal Dutch Shell plc and its subsidiaries accounted for 20 percent, 11 percent, and 15 percent, respectively, of the Company s worldwide oil and gas production revenues. In 2011, purchases by the Vitol Group accounted for 13 percent of the Company s worldwide oil and gas production revenues.

Drilling Statistics

Worldwide in 2012 we participated in drilling 1,486 gross wells, with 1,408 (95 percent) completed as producers. Historically, our drilling activities in the U.S. have generally concentrated on exploitation and extension of existing producing fields rather than exploration. As a general matter, our operations outside of the U.S. focus on a mix of exploration and development wells. In addition to our completed wells, at year-end several wells had not yet reached completion: 70 in the U.S. (55.73 net); 11 in Canada (9.00 net); 26 in Egypt (26.00 net); 2 in Australia (1.65 net); and 4 in Argentina (3.75 net).

The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years:

	Net Exploratory			Net Development			Total Net Wells		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
2012									
United States	9.5	3.5	13.0	746.0	9.6	755.6	755.5	13.1	768.6
Canada	5.0	7.5	12.5	110.3	14.0	124.3	115.3	21.5	136.8
Egypt	28.0	22.5	50.5	144.4	1.0	145.4	172.4	23.5	195.9
Australia	1.9	2.7	4.6	1.3	0.7	2.0	3.2	3.4	6.6
North Sea	1.3	0.0	1.3	11.7	3.9	15.6	13.0	3.9	16.9
Argentina	2.0	0.0	2.0	23.0	0.0	23.0	25.0	0.0	25.0
Other International	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.5	0.5
Total	47.7	36.7	84.4	1,036.7	29.2	1,065.9	1,084.4	65.9	1,150.3
2011									
United States	12.4	5.0	17.4	522.0	17.0	539.0	534.4	22.0	556.4
Canada	4.0	5.0	9.0	77.2	5.0	82.2	81.2	10.0	91.2
Egypt	28.2	19.8	48.0	112.6	6.0	118.6	140.8	25.8	166.6
Australia	1.0	2.3	3.3	1.0	0.0	1.0	2.0	2.3	4.3
North Sea	0.0	0.3	0.3	10.7	1.9	12.6	10.7	2.2	12.9
Argentina	4.0	1.0	5.0	29.4	0.3	29.7	33.4	1.3	34.7
Total	49.6	33.4	83.0	752.9	30.2	783.1	802.5	63.6	866.1
2010									
United States	3.7	2.2	5.9	309.2	12.7	321.9	312.9	14.9	327.8
Canada	6.5	1.5	8.0	122.3	5.7	128.0	128.8	7.2	136.0
Egypt	19.4	18.5	37.9	144.8	5.5	150.3	164.2	24.0	188.2
Australia	5.5	3.4	8.9	4.5	1.3	5.8	10.0	4.7	14.7
North Sea	1.0	1.2	2.2	10.7	5.8	16.5	11.7	7.0	18.7
Argentina	1.8	2.7	4.5	43.3	0.3	43.6	45.1	3.0	48.1
Total	37.9	29.5	67.4	634.8	31.3	666.1	672.7	60.8	733.5

Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of December 31, 2012, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	13,762	9,192	5,375	3,149	19,137	12,341
Canada	2,195	997	9,065	7,744	11,260	8,741
Egypt	977	937	79	74	1,056	1,011
Australia	49	25	13	8	62	33
North Sea	151	99	23	12	174	111
Argentina	474	397	417	383	891	780
Total	17,608	11,647	14,972	11,370	32,580	23,017

Gross natural gas and crude oil wells include 1,625 wells with multiple completions.

Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGL, and gas production volumes, average lease operating expenses per boe (including transportation costs but excluding severance and other taxes), and average sales prices for each of the countries where we have operations:

	Production			Average	Average Sales Price		
Year Ended December 31,	**Oil (MMbbls)**	**NGLs (MMbbls)**	**Gas (Bcf)**	**Lease Operating Cost per Boe**	**Oil (Per bbl)**	**NGLs (Per bbl)**	**Gas (Per Mcf)**
2012							
United States	49.1	12.3	312.6	$ 12.83	$ 94.98	$ 32.19	$ 3.74
Canada	5.8	2.3	219.9	13.87	84.89	34.63	3.42
Egypt	36.5		129.5	7.73	110.92		3.90
Australia	10.6		78.3	9.08	115.22		4.55
North Sea	23.3	0.6	21.0	12.38	107.97	77.11	8.95
Argentina	3.5	1.1	78.1	10.85	75.89	21.55	2.87
Total	128.8	16.3	839.4	11.49	102.53	33.45	3.80
2011							
United States	43.6	8.1	315.6	$ 11.80	$ 95.51	$ 48.42	$ 4.91
Canada	5.2	2.2	230.9	13.86	93.19	45.72	4.47
Egypt	37.9		133.4	7.19	109.92		4.66
Australia	14.0		67.6	7.80	111.22		2.69
North Sea	19.9		0.8	11.61	104.09		22.25
Argentina	3.5	1.1	77.5	9.83	68.02	27.90	2.64
Total	124.1	11.4	825.8	10.62	102.19	45.95	4.37
2010							
United States	35.3	5.0	266.8	$ 11.40	$ 76.13	$ 41.45	$ 5.28
Canada	5.3	1.1	144.5	13.46	72.83	36.61	4.48
Egypt	36.2		136.8	5.56	79.45		3.62
Australia	16.7		72.9	6.41	77.32		2.24
North Sea	20.8		0.9	9.23	76.66		18.64
Argentina	3.6	1.2	67.5	7.97	57.47	27.08	1.96
Total	117.9	7.3	689.4	9.20	76.69	38.58	4.15

Gross and Net Undeveloped and Developed Acreage

The following table sets out our gross and net acreage position as of December 31, 2012, in each country where we have operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**
United States	7,447,487	4,896,442	4,873,810	2,609,338
Canada	2,659,323	2,328,842	4,278,252	3,226,076
Egypt	7,934,690	5,142,158	1,800,720	1,693,216
Australia	7,058,038	3,854,352	880,467	534,665
North Sea	563,129	245,729	159,961	94,448
Argentina	4,182,067	3,106,969	221,422	188,795
Total	29,844,734	19,574,492	12,214,632	8,346,538

As of December 31, 2012, we had 5,229,947, 1,940,328, and 2,596,636 net acres scheduled to expire by December 31, 2013, 2014, and 2015, respectively, if production is not established or we take no other action to extend the terms. We strive to continue the terms of many of these licenses and concession areas through operational or administrative actions, but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third-parties including governments.

As of December 31, 2012, 37 percent of U.S. net undeveloped acreage and 47 percent of Canadian undeveloped acreage was held by production.

Estimated Proved Reserves and Future Net Cash Flows

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate, and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods. The Company reports all estimated proved reserves held under production-sharing arrangements utilizing the economic interest method, which excludes the host country s share of reserves.

Estimated reserves that can be produced economically through application of improved recovery techniques are included in the proved classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating its proved reserves, Apache uses several different traditional methods that can be classified in three general categories: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy with similar properties. Apache will, at times, utilize additional technical analysis, such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods, to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of our reserve estimates.

Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time period.

The following table shows proved oil, NGL, and gas reserves as of December 31, 2012, based on average commodity prices in effect on the first day of each month in 2012, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. This table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products.

	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Total (MMboe)
Proved Developed:				
United States	474	155	2,354	1,021
Canada	80	22	1,735	391
Egypt	107		690	222
Australia	29		596	128
North Sea	120	2	93	138
Argentina	16	5	365	82
Proved Undeveloped:				
United States	203	61	832	403
Canada	71	12	403	150
Egypt	17		205	51
Australia	35		1,074	214
North Sea	28		20	32
Argentina	3	1	97	20
TOTAL PROVED	1,183	258	8,464	2,852

As of December 31, 2012, Apache had total estimated proved reserves of 1,441 MMbbls of crude oil, condensate, and NGLs and 8.5 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 2.9 billion barrels of oil or 17.1 Tcf of natural gas, of which oil represents 41 percent. As of December 31, 2012, the Company s proved developed reserves totaled 1,982 MMboe and estimated PUD reserves totaled 870 MMboe, or approximately 30 percent of worldwide total proved reserves. Apache has elected not to disclose probable or possible reserves in this filing.

The Company s estimates of proved reserves, proved developed reserves and PUD reserves as of December 31, 2012, 2011, and 2010, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 14 Supplemental Oil and Gas Disclosures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. Estimated future net cash flows as of December 31, 2012 and 2011, were calculated using a discount rate of 10 percent per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

Proved Undeveloped Reserves

The Company s total estimated PUD reserves of 870 MMboe as of December 31, 2012, decreased by 128 MMboe from 998 MMboe of PUD reserves estimated at the end of 2011. Driven by the significant decline in North America natural gas prices, a portion of our PUD reserves fell below the threshold for economic development and were removed from our proved reserves balance. The majority of these pricing revisions were associated with dry gas development projects in Canada. During the year, Apache converted 133 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America, we converted 98 MMboe, with the remaining 35 MMboe in our international areas. We acquired 47 MMboe of PUD reserves during the year. We added 158 MMboe of new PUD reserves through extensions and discoveries and had negative revisions of 200 MMboe associated with changes in product prices and revised development plans.

During the year, a total of approximately $3.4 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2011. A portion of our costs incurred each year relate to development projects that will be converted to proved developed reserves in future years. We spent $1.5 billion on PUD reserve development activity in North America and $1.9 billion in the international areas. Other than our Julimar/Brunello development project, which is tied to the construction schedule of the Wheatstone LNG project, with projected first production in 2016, we had no material amounts of PUD reserves that have remained undeveloped for five years or more after they were initially disclosed as PUD reserves and no material amounts of PUD reserves which are scheduled to be developed beyond five years from December 31, 2012.

Preparation of Oil and Gas Reserve Information

Apache emphasizes that its reported reserves are reasonably certain estimates which, by their very nature, are subject to revision. These estimates are reviewed throughout the year and revised either upward or downward, as warranted.

Apache s proved reserves are estimated at the property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers that is independent of the operating groups. These engineers interact with engineering and geoscience personnel in each of Apache s operating areas and with accounting and marketing employees to obtain the necessary data for projecting future production, costs, net revenues, and ultimate recoverable reserves. All relevant data is compiled in a computer database application, to which only authorized personnel are given security access rights consistent with their assigned job function. Reserves are reviewed internally with senior management and presented to Apache s Board of Directors in summary form on a quarterly basis. Annually, each property is reviewed in detail by our corporate and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable.

Apache s Executive Vice President of Corporate Reservoir Engineering is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating any reserves audits conducted by a third-party engineering firm. He has a Bachelor of Science degree in Petroleum Engineering and over 30 years of industry experience with positions of increasing responsibility within Apache s corporate reservoir engineering department. The Executive Vice President of Corporate Reservoir Engineering reports directly to our Chairman and Chief Executive Officer.

The estimate of reserves disclosed in this Annual Report on Form 10-K is prepared by the Company s internal staff, and the Company is responsible for the adequacy and accuracy of those estimates. However, the Company engages Ryder Scott Company, L.P. Petroleum Consultants (Ryder Scott) to review our processes and the reasonableness of our estimates of proved hydrocarbon liquid and gas reserves. Apache selects the properties for review by Ryder Scott based primarily on relative reserve value. We also consider other factors such as geographic location, new wells drilled during the year and reserves volume. During 2012, the properties selected for each country ranged from 77 to 99 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 86 percent of the reserves value of our international proved reserves and of the new wells drilled in each country. In addition, all fields containing five percent or more of the Company s total proved reserves volume were included in Ryder Scott s review. The review covered 83 percent of total proved reserves, including 86 percent of proved developed reserves and 74 percent of PUD reserves.

During 2012, 2011, and 2010, Ryder Scott s review covered 88, 81, and 72 percent, respectively, of the Company s worldwide estimated proved reserves value and 83, 70, and 63 percent, respectively, of the Company s total proved reserves volume. Ryder Scott s review of 2012 covered 81 percent of U.S., 78 percent of Canada, 64 percent of Argentina, 99 percent of Australia, 84 percent of Egypt, and 88 percent of the U.K. s total proved reserves. Ryder Scott s review of 2011 covered 68 percent of U.S., 69 percent of Canada, 58 percent of Argentina, 99 percent of Australia, 62 percent of Egypt, and 61 percent of the U.K. s total proved reserves. Ryder Scott s review of 2010 covered 59 percent of U.S., 42 percent of Canada, 64 percent of Argentina, 99 percent of Australia, 83 percent of Egypt, and 83 percent of the U.K. s total proved reserves. We have filed Ryder Scott s independent report as an exhibit to this Form 10-K.

According to Ryder Scott s opinion, based on their review, including the data, technical processes, and interpretations presented by Apache, the overall procedures and methodologies utilized by Apache in determining the proved reserves comply with the current SEC regulations, and the overall proved reserves for the reviewed properties as estimated by Apache are, in aggregate, reasonable within the established audit tolerance guidelines as set forth in the Society of Petroleum Engineers auditing standards.

Employees

On December 31, 2012, we had 5,976 employees.

Offices

Our principal executive offices are located at One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400. At year-end 2012, we maintained regional exploration and/or production offices in Tulsa, Oklahoma; Houston, Texas; Midland, Texas; Calgary, Alberta; Cairo, Egypt; Perth, Western Australia; Aberdeen, Scotland; and Buenos Aires, Argentina. Apache leases all of its primary office space, with the exception of our Midland office, which we own. The current lease on our principal executive offices runs through December 31, 2018. For information regarding the Company s obligations under its office leases, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Contractual Obligations and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Title to Interests

As is customary in our industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time we acquire properties. We believe that our title to all of the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in our operations. The interests owned by us may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as production payments, net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in our operations.

Additional Information about Apache

In this section, references to we, us, our, and Apache include Apache Corporation and its consolidated subsidiaries, unless otherwise specifical stated.

Remediation Plans and Procedures

Apache and its wholly owned subsidiary, Apache Deepwater LLC (ADW), developed Oil Spill Response Plans (the Plans) for their respective Gulf of Mexico operations to ensure rapid and effective responses to spill events that may occur on such entities operated properties as required by the Bureau of Safety and Environmental Enforcement (BSEE) 30 CFR 254.30. Annually, drills are conducted to measure and maintain the effectiveness of the Plans. These drills include the participation of spill response contractors, representatives of the Clean Gulf Associates, and representatives of governmental agencies. In the event of a spill, the CGA is the primary oil spill response association available to Apache and ADW. Apache and ADW have received approval for the Plans from BSEE. Apache and ADW personnel each review their respective Plan biennially and update where necessary.

Both Apache and ADW are members of, and Apache has an employee representative on the executive committee of, Clean Gulf Associates (CGA), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico. CGA was created to provide a means of effectively staging response equipment and providing immediate spill response for its member companies operations in the Gulf of Mexico. Until December 31, 2012, CGA s equipment was maintained by the Marine Spill Response Corporation (MSRC), a national, private, not-for-profit marine spill response organization, which is funded by grants from the Marine Preservation Association. CGA s equipment maintained by MSRC included a high-volume open sea barge oil skimming system, 11 rigid sweeping arms, an oceangoing boom barge with 25,000 feet of offshore containment boom, a fire boom, six fast response vessels, 12 fast response skimming units, multiple shallow water skimming and recovery systems, wildlife cleaning and rehabilitation facilities, and dispersant inventory. In the event of a spill, MSRC stood ready to mobilize all of this equipment to CGA members. MSRC also handled the maintenance and mobilization of CGA non-marine equipment. Effective January 1, 2013, CGA s marine and non-marine equipment is now maintained by the Clean Gulf Associates Service, LLC. In the event of a spill, this equipment, which is positioned at various staging points around the Gulf, is ready to be mobilized. In addition, CGA has contracted with Airborne Support Inc. to provide aircraft and dispersant capabilities for CGA member companies. In 2012, Apache incurred charges for CGA of approximately $380,000 based on a per-member fee and annual production.

In the event that CGA resources are already being utilized, other associations are available to Apache. Apache is a member of Oil Spill Response Limited (OSRL), which entitles any Apache entity worldwide to access OSRL s service. OSRL has access to resources from the Global Response Network, a collaboration of seven major oil industry funded spill response organizations worldwide. OSRL has equipment stockpiles in Bahrain, Singapore, and Southampton that currently include approximately 153 skimmers, booms (of approximately 12,000 meters), two Hercules aircraft for equipment deployment and aerial dispersant spraying, two additional aircraft, dispersant spray systems and dispersant, floating storage tanks, all-terrain vehicles, and various other equipment. If necessary, OSRL s resources may be, and have been, deployed to areas across the globe, including the Gulf of Mexico. In addition, in February 2012, ADW became a member of MSRC and National Response Corporation (NRC), and their resources are available to ADW for its deepwater Gulf of Mexico operations. Furthermore, the spill response resources of other organizations are also available to both Apache and ADW as non-members, albeit at a higher cost. MSRC has an extensive inventory of oil spill response equipment, independent of and in addition to CGA s equipment. MSRC s equipment currently includes 19 oil spill response barges with storage capacities between 12,000 and 68,000 barrels, 68 shallow water barges, over 290 skimming systems, approximately 50 self-propelled skimming vessels, 7 mobile communication suites with internet and telephone connections, as well as marine and aviation communication capabilities, various small crafts and shallow water vessels, 22,500 feet of fire boom, and 6 dispersant aircraft. MSRC has contracts in place with over 100 environmental contractors around the country, in addition to hundreds of other companies that provide support services during spill response. In the event of a spill, MSRC will activate these contractors as necessary to provide additional resources or support services requested by its customers. NRC owns a variety of equipment, currently including shallow water portable barges, boom, high capacity skimming systems, inland workboats, vacuum transfer units, and mobile communication centers. NRC has access to a vessel fleet of more than 328 offshore vessels and supply boats worldwide, as well as access to hundreds of tugs and oil barges from its tug and barge clients. The equipment and resources available to the MSRC and the NRC changes from time to time, and current information is generally available on each company s website. In 2012, Apache s Gulf of Mexico Deepwater region incurred charges for NRC of $12,000 based on annual production and charges for MSRC of approximately $735,000 based on annual production and total wells spud in 2012.

ADW has also retained the Helix Well Containment Group (HWCG) in conjunction with its CGA membership. HWCG is a consortium of 24 deepwater operators in the Gulf of Mexico that have worked on expanding capabilities to rapidly respond to subsea well incidents like the Deepwater Horizon incident. In June 2011, HWCG announced that it is now capable of responding to a subsea well containment incident in water depths of up to 10,000 feet. Each HWCG member company has entered into a mutual aid agreement, allowing any member to draw upon the technical expertise and resources of the group in the event of an incident. ADW s 2012 membership dues were approximately $1 million.

In 2011, ADW also became a member of the Marine Well Containment Company (MWCC) to fulfill the government s permit requirements for containment and oil spill response plans in deepwater Gulf of Mexico operations. In March 2012, ADW assigned its interest in MWCC to Apache Well Containment LLC, another wholly owned Apache subsidiary. MWCC is a not-for-profit, stand-alone organization whose goal is to improve capabilities for containing an underwater well control incident in the U.S. Gulf of Mexico. MWCC is currently developing a billion-dollar expanded containment system, which is expected to be available in 2013. The MWCC owns and maintains an interim containment system, which became available for use in February 2011. The interim containment system includes a subsea capping stack with the ability to shut in oil flow or to flow the oil via flexible pipes and risers to surface vessels. The system also includes subsea dispersant injection equipment, manifolds, and, through mutual aid among members, capture vessels to provide surface processing and storage. The interim system is designed to meet the BSEE requirements. It can operate in water depths up to 8,000 feet and has storage and processing capacity for up to 60,000 b/d and 120 MMcf/d. The capability of the interim containment system continues to grow as components of the expanded system are completed and delivered. The expanded system is designed to operate in 10,000 feet of water and process up to 100,000 b/d and 200 MMcf/d. Membership in MWCC is open to all companies operating in the U.S. Gulf of Mexico. Members and their affiliates have access to the interim containment system, as well as the expanded system once construction is completed. Non-members will also have access to the systems through a service agreement and fee. As of December 31, 2012, Apache s investment in MWCC totals approximately $88 million.

Apache also participates in a number of industry-wide task forces that are studying ways to better access and control blowouts in subsea environments and increase containment and recovery methods. Two such task forces are the Subsea Well Control and Containment Task Force and the Offshore Operating Procedures Task Force.

Competitive Conditions

The oil and gas business is highly competitive in the exploration for and acquisitions of reserves, the acquisition of oil and gas leases, equipment and personnel required to find and produce reserves, and in the gathering and marketing of oil, gas, and natural gas liquids. Our competitors include national oil companies, major integrated oil and gas companies, other independent oil and gas companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers.

Certain of our competitors may possess financial or other resources substantially larger than we possess or have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for leases or drilling rights.

However, we believe our diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across six countries, and our balanced production mix between oil and gas, our management and incentive systems, and our experienced personnel give us a strong competitive position relative to many of our competitors who do not possess similar political, geographic, and production diversity. Our global position provides a large inventory of geologic and geographic opportunities in the six countries in which we have producing operations to which we can reallocate capital investments in response to changes in commodity prices, local business environments, and markets. It also reduces the risk that we will be materially impacted by an event in a specific area or country.

Environmental Compliance

As an owner or lessee and operator of oil and gas properties and facilities, we are subject to numerous federal, provincial, state, local, and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Although environmental requirements have a substantial impact upon the energy industry, as a whole, we do not believe that these requirements affect us differently, to any material degree, than other companies in our industry.

We have made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry. We have established policies for continuing compliance with environmental laws and regulations, including regulations applicable to our operations in all countries in which we do business. We have established operating procedures and training programs designed to limit the environmental impact of our field facilities and identify and comply with changes in existing laws and regulations. The costs incurred under these policies and procedures are inextricably connected to normal operating expenses such that we are unable to separate expenses related to environmental matters; however, we do not believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on our capital expenditures, earnings, or competitive position.

ITEM 1A. ***RISK FACTORS***

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Additional risks relating to our securities may be included in the prospectuses for securities we issue in the future.

Future economic conditions in the U.S. and key international markets may materially adversely impact our operating results.

The U.S. and other world economies are slowly recovering from a global financial crisis and recession that began in 2008. Growth has resumed but is modest and at an unsteady rate. The continuation of current global market conditions, uncertainty or further deterioration, including the economic instability in Europe, is likely to have significant long-term effects, including a future global economic growth rate that is slower than in the years leading up to the crisis, and more volatility may occur before any sustainable growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

Crude oil and natural gas prices are volatile, and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results, and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2012 ranged from a high of $109.77 per barrel to a low of $77.69 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2012 ranged from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu. The market prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions, and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability, changes in governments, or armed conflict) in crude oil or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil and natural gas;
- the price and availability of alternative fuels, including coal and biofuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;

electricity generation;

domestic and foreign governmental regulations and taxes; and

the overall economic environment.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, and/or ability to fund planned capital expenditures and operations;
- reducing the amount of crude oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income, and cash flows;
- limiting our access to sources of capital, such as equity and long-term debt;
- a reduction in the carrying value of our crude oil and natural gas properties; or
- a reduction in the carrying value of goodwill.

Our ability to sell natural gas or oil and/or receive market prices for our natural gas or oil may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or capital constraints that limit the ability of third parties to construct gathering systems, processing facilities, or interstate pipelines to transport our production, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows.

Weather and climate may have a significant adverse impact on our revenues and productivity.

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impact the price we receive for the commodities we produce. In addition, our exploration and development activities and equipment can be adversely affected by severe weather, such as hurricanes in the Gulf of Mexico or cyclones offshore Australia, which may cause a loss of production from temporary cessation of activity or lost or damaged equipment. Our planning for normal climatic variation, insurance programs, and emergency recovery plans may inadequately mitigate the effects of such weather conditions, and not all such effects can be predicted, eliminated, or insured against.

Our operations involve a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents.

Our operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil and natural gas, including:

- well blowouts, explosions, and cratering;
- pipeline ruptures and spills;
- fires;

formations with abnormal pressures;

equipment malfunctions;

hurricanes and/or cyclones, which could affect our operations in areas such as on- and offshore the Gulf Coast and Australia, and other natural disasters; and

surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks, or natural disasters such as hurricanes, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, or fire at a location where our equipment and services are used, or ground water contamination from hydraulic fracturing chemical additives may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture, or surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives could result in extensive environmental pollution and substantial remediation expenses. If a significant amount of our production is interrupted, our containment efforts prove to be ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and, in turn, our results of operations could be materially and adversely affected.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have experienced cyber attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. Further, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

The additional deepwater drilling laws and regulations, delays in the processing and approval of permits and other related developments in the Gulf of Mexico as well as our other locations resulting from the Deepwater Horizon incident could adversely affect Apache s business.

In response to the Deepwater Horizon incident in the U.S. Gulf of Mexico in April 2010, and as directed by the Secretary of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) issued new guidelines and regulations regarding safety, environmental matters, drilling equipment, and decommissioning applicable to drilling in the Gulf of Mexico. These new regulations have imposed additional requirements with respect to development and production activities in the Gulf of Mexico and have delayed the approval of applications to drill in both deepwater and shallow-water areas.

Further, at this time, we cannot predict with any certainty what further impact, if any, the Deepwater Horizon incident may have on the regulation of offshore oil and gas exploration and development activity, or on the cost or availability of insurance coverage to cover the risks of such operations. The enactment of new or stricter regulations in the United States and other countries and increased liability for companies operating in this sector could adversely affect Apache s operations in the U.S. Gulf of Mexico as well as in our other locations.

Our commodity price risk management and trading activities may prevent us from benefiting fully from price increases and may expose us to other risks.

To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds, and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We are exposed to counterparty credit risk as a result of our receivables.

We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas, and NGLs to a variety of purchasers. As operator, we pay expenses and bill our non-operating partners for their respective shares of costs. Some of our purchasers and non-operating partners may experience liquidity problems and may not be able to meet their financial obligations. Nonperformance by a trade creditor or non-operating partner could result in significant financial losses.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, and commodity pricing levels and others are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require the Company to post letters of credit or other forms of collateral for certain obligations.

Market conditions may restrict our ability to obtain funds for future development and working capital needs, which may limit our financial flexibility.

While the credit markets have recovered in the wake of the global financial crises, they remain vulnerable to unpredictable shocks. We have a significant development project inventory and an extensive exploration portfolio, which will require substantial future investment. We and/or our partners may need to seek financing in order to fund these or other future activities. Our future access to capital, as well as that of our partners and contractors, could be limited if the debt or equity markets are constrained. This could significantly delay development of our property interests.

Our ability to declare and pay dividends is subject to limitations.

The payment of future dividends on our capital stock is subject to the discretion of our board of directors, which considers, among other factors, our operating results, overall financial condition, credit-risk considerations, and capital requirements, as well as general business and market conditions. Our board of directors is not required to declare dividends on our common stock and may decide not to declare dividends.

Any indentures and other financing agreements that we enter into in the future may limit our ability to pay cash dividends on our capital stock, including common stock. In the event that any of our indentures or other financing agreements in the future restrict our ability to pay dividends in cash on the mandatory convertible preferred stock, we may be unable to pay dividends in cash on the common stock unless we can refinance amounts outstanding under those agreements. In addition, under Delaware law, dividends on capital stock may only be paid from surplus, which is defined as the amount by which our total assets exceeds the sum of our total liabilities, including contingent liabilities, and the amount of our capital; if there is no surplus, cash dividends on capital stock may only be paid from our net profits for the then current and/or the preceding fiscal year. Further, even if we are permitted under our contractual obligations and Delaware law to pay cash dividends on common stock, we may not have sufficient cash to pay dividends in cash on our common stock.

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.

The production rate from oil and gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through exploration and development activities or, through engineering studies, identify additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase.

We may not realize an adequate return on wells that we drill.

Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The wells we drill or participate in may not be productive, and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors including, but not limited to:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts, and surface cratering;
- marine risks such as capsizing, collisions, and hurricanes;

other adverse weather conditions; and

increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Future drilling activities may not be successful, and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.

Material differences between the estimated and actual timing of critical events may affect the completion and commencement of production from development projects.

We are involved in several large development projects the completion of which may be delayed beyond our anticipated completion dates. Our projects may be delayed by project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, and other unforeseen events. Delays and differences between estimated and actual timing of critical events may adversely affect our large development projects and our ability to participate in large-scale development projects in the future.

We may fail to fully identify potential problems related to acquired reserves or to properly estimate those reserves.

Although we perform a review of properties that we acquire that we believe is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us as a buyer to become sufficiently familiar with the properties to assess fully and accurately their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future production rates and costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates. In addition, there can be no assurance that acquisitions will not have an adverse effect upon our operating results, particularly during the periods in which the operations of acquired businesses are being integrated into our ongoing operations.

The BP Acquisition and/or our liabilities could be adversely affected in the event one or more of the BP entities become the subject of a bankruptcy case.

In light of the extensive costs and liabilities related to the oil spill in the Gulf of Mexico in 2010, there was public speculation as to whether one or more of the BP entities could become the subject of a case or proceeding under Title 11 of the United States Code or any other relevant insolvency law or similar law (which we collectively refer to as Insolvency Laws). In the event that one or more of the BP entities were to become the subject of such a case or proceeding, a court may find that the three definitive purchase and sale agreements (the BP Purchase Agreements) we entered into in connection with our 2010 acquisition of properties from BP (the BP Properties) are executory contracts, in which case such BP entities may, subject to relevant Insolvency Laws, have the right to reject the agreements and refuse to perform their future obligations under them. In this event, our ability to enforce our rights under the BP Purchase Agreements could be adversely affected.

Additionally, in a case or proceeding under relevant Insolvency Laws, a court may find that the sale of the BP Properties constitutes a constructive fraudulent conveyance that should be set aside. While the tests for determining whether a transfer of assets constitutes a constructive fraudulent conveyance vary among jurisdictions, such a determination generally requires that the seller received less than a reasonably equivalent value in exchange for such transfer or obligation and the seller was insolvent at the time of the transaction, or was rendered insolvent or left with unreasonably small capital to meet its anticipated business needs as a result of the transaction. The applicable time periods for such a finding also vary among jurisdictions, but generally range from two to six years. If a court were to make such a determination in a proceeding under relevant Insolvency Laws, our rights under the BP Purchase Agreements, and our rights to the BP Properties, could be adversely affected.

Crude oil and natural gas reserves are estimates, and actual recoveries may vary significantly.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices, except where contractual arrangements exist; therefore, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the effects of regulations by governmental agencies, including changes to severance and excise taxes;
- future operating costs and capital expenditures; and
- workover and remediation costs.

For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of those reserves and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

Additionally, because some of our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

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

A sizeable portion of our acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, 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, oil and natural gas prices, the availability and cost of capital, drilling, and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

We may incur significant costs related to environmental matters.

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, provincial, state, local, and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Our efforts to limit our exposure to such liability and cost may prove inadequate and result in significant adverse effect on our results of operations. In addition, it is possible that the increasingly strict requirements imposed by environmental laws and enforcement policies could require us to make significant capital expenditures. Such capital expenditures could adversely impact our cash flows and our financial condition.

Our North American operations are subject to governmental risks that may impact our operations.

Our North American operations have been, and at times in the future may be, affected by political developments and by federal, state, provincial, and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls, and environmental protection laws and regulations. New political developments, laws, and regulations may adversely impact our results on operations.

Pending regulations related to emissions and the impact of any changes in climate could adversely impact our business.

Several countries where Apache operates including Australia, Canada, and the United Kingdom either tax or assess some form of greenhouse gas (GHG) related fees on Company operations. Exposure has not been material to date, although a change in existing regulations could adversely affect our cash flows and results of operations.

In the event the predictions for rising temperatures and sea levels suggested by reports of the United Nations Intergovernmental Panel on Climate Change do transpire, we do not believe those events by themselves are likely to impact the Company s assets or operations. However, any increase in severe weather could have a material adverse effect on our assets and operations.

The proposed U.S. federal budget for fiscal year 2014, when released, is expected to include certain provisions that, if passed, will have an adverse effect on our financial position, results of operations, and cash flows.

To date, the Office of Management and Budget has not released a summary of the proposed U.S. federal budget for fiscal year 2014. When released, it is anticipated that as a result of possible significant deficit reduction or comprehensive tax reform measures currently under consideration the proposed budget may repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. These provisions include elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; repeal of the manufacturing tax deduction for oil and natural gas companies; and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities in the U.S. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post collateral (commonly referred to as margin) for such transactions. The Act provides for a potential exception from these clearing and collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. We expect to qualify as a commercial end-user. As required by the Dodd-Frank Act, the Commodities Futures and Trading Commission (CFTC) has promulgated numerous rules to define these terms. In addition, it is possible that the CFTC, in conjunction with prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral.

We use derivative instruments with respect to a portion of our expected crude oil and natural gas production in order to reduce the impact of commodity price fluctuations and enhance the stability of cash flows to support our capital investment programs and acquisitions. Given our current investment grade status, our current derivative contracts do not require the posting of margin regardless of the size of our liability positions.

Depending on the rules and definitions adopted by the CFTC and prudential regulators, we could be required to post significant amounts of collateral with our dealer counterparties for derivative transactions. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and also cause us to incur additional debt and/or reduce capital investment. In addition, the final CFTC rules may also require the counterparties to our derivative instruments to move some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase our operating and capital costs.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing, or are considering doing so. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in very tight formations.

Although it is not possible at this time to predict the final outcome of the legislation regarding hydraulic fracturing, any new federal, state, or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions in the U.S.

A deterioration of conditions in Egypt or changes in the economic and political environment in Egypt could have an adverse impact on our business.

In February 2011, the former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power, announcing that it would remain in power until the presidential and parliamentary elections could be held. In June 2012, Mohamed Morsi of the Muslim Brotherhood s Freedom and Justice Party was elected as Egypt s new president. In December 2012 the people of Egypt ratified a new constitution. Under the new constitution, the government must hold elections for the lower house of parliament within 60 days. Deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, expropriation of our assets or resource nationalization, and/or forced renegotiation or modification of our existing contracts with EGPC could materially and adversely affect our business, financial condition, and results of operations. Our operations in Egypt contributed 20 percent of our 2012 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2012, 17 percent of our estimated discounted future net cash flows and 7 percent of our net capitalized oil and gas property was attributable to Egypt.

International operations have uncertain political, economic, and other risks.

Our operations outside North America are based primarily in Egypt, Australia, the United Kingdom, and Argentina. On a barrel equivalent basis, approximately 44 percent of our 2012 production was outside North America, and approximately 31 percent of our estimated proved oil and gas reserves on December 31, 2012 were located outside North America. As a result, a significant portion of our production and resources are subject to the increased political and economic risks and other factors associated with international operations including, but not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation and resource nationalization, forced renegotiation or modification of existing contracts;
- import and export regulations;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- price control;
- transportation regulations and tariffs;
- constrained natural gas markets dependent on demand in a single or limited geographical area;
- exchange controls, currency fluctuations, devaluation, or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the United States affecting foreign trade, including trade sanctions;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;
- the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the United States; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

Foreign countries have occasionally asserted rights to oil and gas properties through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to us by another country, our interests could decrease in value or be lost. Even our smaller international assets may affect our overall business and results of operations by distracting management s attention from our more significant assets. Various regions of the world in which we operate have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might result in a substantially more hostile attitude toward foreign investments such as ours. In an extreme case, such a change could result in termination of contract rights and expropriation of our assets. This could adversely affect our interests and our future profitability.

The impact that future terrorist attacks or regional hostilities may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants, and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

In addition, continued regional conflict in the Middle East could have the following results, among others:

- volatility in global crude prices, which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world s crude oil supply if transportation avenues are disrupted, leading to further commodity price volatility;
- damage to or destruction of our wells, production facilities, receiving terminals, or other operating assets;
- inability of our service equipment providers to deliver items necessary for us to conduct our operations in the Middle East; and
- lack of availability of drilling rigs, oilfield equipment, or services if third-party providers decide to exit the region.

Our operations are sensitive to currency rate fluctuations.

Our operations are sensitive to fluctuations in foreign currency exchange rates, particularly between the U.S. dollar and the Canadian dollar, the Australian dollar, and the British Pound. Our financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect our results of operations, particularly through the weakening of the U.S. dollar relative to other currencies.

We face strong industry competition that may have a significant negative impact on our results of operations.

Strong competition exists in all sectors of the oil and gas exploration and production industry. We compete with major integrated and other independent oil and gas companies for acquisition of oil and gas leases, properties, and reserves, equipment, and labor required to explore, develop, and operate those properties, and marketing of oil and natural gas production. Crude oil and natural gas prices impact the costs of properties available for acquisition and the number of companies with the financial resources to pursue acquisition opportunities. Many of our competitors have financial and other resources substantially larger than we possess and have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as fluctuating worldwide commodity prices and levels of production, the cost and availability of alternative fuels, and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. These competitive pressures may have a significant negative impact on our results of operations.

Our insurance policies do not cover all of the risks we face, which could result in significant financial exposure.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other events such as blowouts, cratering, fire and explosion and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property and the environment. Our international operations are also subject to political risk. The insurance coverage that we maintain against certain losses or liabilities arising from our operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to us against all operational risks.

ITEM 1B. ***UNRESOLVED STAFF COMMENTS***

As of December 31, 2012, we did not have any unresolved comments from the SEC staff that were received 180 or more days prior to year-end.

ITEM 3. ***LEGAL PROCEEDINGS***

The information set forth under Legal Matters and Environmental Matters in Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. ***MINE SAFETY DISCLOSURES***

None.

PART II

ITEM 5. ***MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES***

During 2012, Apache common stock, par value $0.625 per share, was traded on the New York and Chicago Stock Exchanges and the NASDAQ National Market under the symbol APA. The table below provides certain information regarding our common stock for 2012 and 2011. Prices were obtained from The New York Stock Exchange, Inc. Composite Transactions Reporting System. Per-share prices and quarterly dividends shown below have been rounded to the indicated decimal place.

	2012				2011			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 112.09	$ 91.48	$ 0.17	$ 0.15	$ 132.50	$ 110.29	$ 0.15	