APACHE CORP
Form 10-K
February 29, 2012
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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, 2011

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	New York Stock Exchange

7.75% Notes Due 2029 Irrevocably and Unconditionally 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, 2011	$ 47,361,451,733
Number of shares of registrant s common stock outstanding as of January 31, 2012	384,321,970

Documents Incorporated By Reference

Portions of registrant s proxy statement relating to registrant s 2012 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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DESCRIPTION

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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.

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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, offshore the U.K. in the 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 May 20, 2011, 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 also 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.

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

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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 26 years and production 31 out of the past 33 years, a testament to our consistency over the long-term.

Apache pursues opportunities for growth through exploration and development drilling, supplemented by strategic acquisitions. In 2011, we generated approximately $10 billion of cash flows from operations, which enabled us to deliver on an aggressive capital budget investing approximately $8 billion across all of our regions, while paying down nearly $1 billion in debt. Approximately one-quarter of our global capital was spent on leasehold acreage, seismic data, gathering and processing facilities, long-lead development projects, and front-end engineering and design (FEED) studies tied to our LNG projects. Coupled with an active drilling program and an increasing new venture exploration effort, these longer-term investments secure a platform for continued long-term profitable growth.

We have also been significantly active in the acquisition market for the past two years, having identified several opportunities that met our criteria for risk, reward, rate of return, and growth potential. As we head into 2012, Apache continues to be active with recent acquisition announcements in Australia and the Anadarko basin of the central U.S. Each of our acquisitions fit well with our long-term strategy of maintaining a balanced portfolio of core assets by adding high-quality properties with a diversity of geologic and geographic risk, product mix, and reserve life to nearly all of our regions. The properties are strategically positioned with our existing infrastructure and play to the strengths that come with our operating experience.

2012 Acquisitions

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

Central Anadarko basin acquisition Apache announced in January 2012 that we agreed to acquire Cordillera Energy Partners III LLC (Cordillera), a privately held company, for $2.2 billion in cash and approximately 6.3 million shares of Apache common stock. The merger is expected to close in the second quarter of 2012.

2011 Acquisitions

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 Acquisitions

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.

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.

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.

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

In the midst of our heightened exploration, development drilling, and acquisition activity, we have remained committed to our core strategies of maintaining a balanced portfolio, conservative capital structure, and rate of return focus.

Balanced Portfolio of Core Assets

A cornerstone of our long-term strategy is balancing our portfolio of assets through diversity of geologic risk, geographic risk, hydrocarbon mix (crude oil versus natural gas), and reserve life in order to achieve consistency in results. Our portfolio of geographic locations provides variation of all of these factors. We have exploration and production operations in six countries, through ten distinct regions: the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, Gulf Coast Onshore, Permian, and Central regions of the U.S., Canada, Egypt, the U.K. North Sea, Australia, and Argentina.

Each of our regions has achieved an economy of scale providing a vehicle for cost-effective base production and a combination of low- and medium-risk drilling opportunities. The net cash provided by operating activities (cash flows) generated by our current production base funds our worldwide exploitation and drilling program and development capital for prior exploration discoveries. In addition, a portion of our cash flows generated each year is allocated to pursue new exploration targets over our 28 million gross undeveloped acres and new areas around the globe. Our continued diligence on allocating capital across multiple regions and various projects has produced a balanced portfolio of assets that consistently delivers positive cash flows and has become a foundation for future growth opportunities.

In 2011:

- No single region contributed more than 22 percent of our equivalent production or 29 percent of revenue.

- No single region held more than 26 percent of our year-end estimated proved reserves.

- The mixture of reserve life (estimated reserves divided by annual production) in our regions, which offers a balance in timing of investment returns, ranges from five years to 22 years.

- Our balanced product mix provides a measure of protection against price deterioration in a given product while retaining upside potential in the event of a significant increase in the commodity price for either product. In 2011, crude oil and liquids provided 50 percent of our production and 79 percent of our revenue.

- International Dated Brent crudes and sweet crude from the Gulf Coast, which represent 76 percent of our crude oil production, continue to be priced at a significant premium to West Texas Intermediate (WTI)-based prices.

- Our international gas portfolio, which accounted for 34 percent of our 2011 worldwide natural gas production, positions us to take advantage of increasing prices in Argentina and Australia while North American gas prices continue to languish.

Conservative Capital Structure

Maintaining a strong balance sheet and the financial flexibility it provides is a core component of our long-term strategy and we believe one of our most important strategic assets. This approach underpins our ability to weather commodity price volatility and has enabled us to deliver long-term production and reserves growth throughout the cycles of our industry. It is also key in positioning us to pursue value-creating acquisitions when opportunities arise.

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During 2011, we met our objectives to fund our exploration and development capital with operating cash flows and to reduce the Company s debt to $7.2 billion. Specifically, we exited the year with a debt-to-capitalization ratio of 20 percent, down from 25 percent at year-end 2010. In addition, as of December 31, 2011, we had access to $3.3 billion of available committed borrowing capacity, up from $2.4 billion at year-end 2010.

Rate of Return Focus

Another core component to our long-term strategy is focusing on rate of return. We do so through centralized management and incentive systems, decentralized decision making, cost control focus, and the creative application of technology.

Our centralized management and incentive systems provide a uniform process of measuring success across Apache and has instilled a rate-of-return focus into our culture. Our organizational structure incentivizes high rate-of-return activities but allows for appropriate risk-taking to drive future growth and monetize reserves. Results of operations and rate of return on invested capital are measured monthly, reviewed with management quarterly, and utilized to determine annual performance awards. We review capital allocations, at least quarterly, utilizing estimates of internally generated cash flows. We do this through a disciplined and focused process that includes analyzing current economic conditions, projected rate of return on internally generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects and occasionally, new core areas that could enhance our portfolio.

We also use technology to reduce risk, decrease time and costs, and maximize recoveries from reservoirs. Apache scientists and engineers have been granted numerous patents for a range of inventions, from systems used for interpreting seismic data and processing well logs to improvements in drilling and completion techniques.

For a more in-depth discussion of our 2011 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, offshore the U.K. in the North Sea, and Argentina.

The following table sets out a brief comparative summary of certain key 2011 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2011 Production (In MMboe)	Percentage of Total 2011 Production	2011 Production Revenue (In millions)	12/31/11 Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	2011 Gross Wells Drilled	2011 Gross Productive Wells Drilled
United States	104.3	38%	$ 6,104	1,290	43%	702	671
Canada	45.9	17	1,617	764	26	143	131
Total North America	150.2	55	7,721	2,054	69	845	802
Egypt	60.2	22	4,791	292	10	177	147
Australia	25.2	9	1,734	330	11	9	5
North Sea	20.0	7	2,091	197	6	14	11
Argentina	17.5	7	473	117	4	42	40
Total International	122.9	45	9,089	936	31	242	203
Total	273.1	100%	$ 16,810	2,990	100%	1,087	1,005

North America

Apache s North American asset base primarily comprises operations in the Permian Basin, the central U.S., the Gulf Coast areas of the U.S. and operations in Western Canada. In 2011, our North America assets contributed 55 percent of our production and 46 percent of our oil and gas production revenues. At year-end 2011, 69 percent of our estimated proved reserves were located in North America.

United States

Overview We have 10.3 million gross acres across the U.S., approximately half of which is undeveloped. As a result of recent acquisitions and a diversity of growth and opportunity profiles, we divided our U.S. assets into five regions: Permian, Central, Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore. We also have leasehold acreage holdings in Alaska. Our holdings in the U.S. provide a balance of hydrocarbon mix and reserve life and an opportunity for continued exploration. In 2011, 50 percent of our U.S. production and 62 percent of our U.S. year-end reserves were oil and liquids. In addition, the reserve life of our U.S. regions ranged from five to 22 years with the Gulf of Mexico offshore region s shorter-lived reserves balancing longer-lived reserves in the Central and Permian regions. In 2011, 38 percent of Apache s equivalent production and 43 percent of Apache s total year-end reserves were in the U.S.

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. Recent acquisitions have significantly increased Apache s presence in the area and have bolstered an already deep inventory of projects with additional development and exploration opportunities for multiple years. The area is divided into three regions, which include the Gulf of Mexico Shelf, Gulf of Mexico Deepwater, and Gulf Coast Onshore.

In water less than 500 feet deep, 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. The Gulf of Mexico Shelf region has approximately 3 million gross acres covering 622 offshore blocks with nearly 80 percent of the blocks held-by-production. The region contributed 14 percent of our worldwide production and 15 percent of worldwide revenue during 2011. 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 allowing the region to play a vital role in funding investments in other regions. Although regulations issued in 2010 have slowed the issuance of drilling permits for all operators, during 2011 the region drilled or participated in 35 wells with a 71-percent success rate. We drilled 36 wells in 2010 and 20 wells in 2009.

In water greater than 500 feet deep, 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 the Company now owns approximately 750,000 gross acres across 148 blocks as of the end of 2011. The Deepwater region contributed approximately two percent of Apache s worldwide production; however, there are multiple projects underway. The Bushwood, Wide Berth, and Mandy development projects are projected to begin production in the second quarter of 2012 with combined net initial production of 12 Mboe/d. In addition, the larger scale non-operated Lucius project was sanctioned in the fourth quarter of 2011. Apache has an 11.7-percent working interest in this development with first production projected for 2014. The region is also increasing its exploration activity, having recently been awarded four deepwater exploration plans. We expect to drill or participate in drilling nine wells during 2012 compared to two wells drilled in the current year.

Apache s Gulf Coast Onshore region was established in August 2010 to more fully exploit the opportunities built over the years in onshore areas of Texas, Louisiana, and Mississippi. The region has a significant acreage position of approximately 1.4 million gross acres, including 330,000 mineral fee acres. During the year, the region focused on drilling shallow and moderate depth targets, increasing acreage holdings, and expanding our regional 3-D seismic databases. We are also evaluating several unconventional resource opportunities. The region drilled or participated in drilling 50 wells during 2011 and projects drilling approximately 40 wells in 2012, including increased activity in unconventional and deeper exploitation.

In 2012, the Company plans to invest approximately $1.0 billion, $500 million, and $350 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, seismic acquisitions, and plugging and abandonment of wells and platforms. We spent $363 million on abandonment activities in 2011 over the entire Gulf Coast area.

Central Region The Central region includes more than 2,500 producing wells and controls over one million gross acres primarily in western Oklahoma and the Texas panhandle. Most of the region s acreage is held-by-production. The region s reserves and production are primarily natural gas; however, a transformation from vertical to horizontal drilling has evolved over the last two years, and the region is now targeting oil and liquids-rich gas plays given the continued price disparity between oil and gas. The result of focusing on oil and liquid plays was evident during 2011 with oil production nearly doubling and NGL production up 244 percent compared to the prior year. Total region production was up 14 percent as we drilled or participated in drilling 108 wells, 94 percent being completed as producers. The region s year-end 2011 estimated proved reserves represented five percent of Apache s worldwide total.

The primary target for the region s liquids-focused objective has been in the Anadarko basin s Granite Wash play, with 50 wells brought on production during 2011. Thirty-three of these were operated wells that had average 30-day gross rates of approximately 500 b/d and 4.5 MMcf/d. The Granite Wash consists of a series of thick, multi-layered formations of low-permeability and liquids-rich sandstones. We have operated in this area for 50 years drilling vertical wells, but the play has recently re-emerged as a horizontal drilling play with multi-staged fracturing technology. We drilled our first operated horizontal well in the Granite Wash in 2009 and have continued to pursue cost efficiencies and reduce drilling time.

The region has also increased its focus on oil plays in the Anadarko shelf Cherokee formation and the Texas Panhandle Cleveland formation. In 2011, we drilled 12 wells in the Cherokee formation and 10 wells in the Cleveland formation with an average 30-day gross production rate of 350 b/d and 500 Mcf/d.

With its growing success in oil and liquids-rich gas plays, the region has been active on the acquisition and divestiture front. In March 2011, Apache acquired 92,400 net acres in the Whittenburg basin of Oldham County, Texas, which is emerging as a potential new oil play for Apache. The acreage is immediately south of the Panhandle Dolomite field and directly north of two 25-well Canyon Wash fields. For 2012, the region plans to increase its Whittenburg activity level to include horizontal drilling and has recently completed the acquisition of 244 square miles of 3-D seismic data. Separately, in 2011 the region divested its natural gas properties in east Texas. The divestiture, which was completed in December 2011, included dry gas wells that were producing approximately 31 MMcf/d net to Apache.

In January 2012, the Company announced entry into a merger agreement to acquire Cordillera, a privately held company with approximately 254,000 net acres in the Granite Wash play, nearly 18 Mboe/d of current production, and estimated proved reserves of 71.5 MMboe. This doubles Apache s acreage in the Granite Wash area and adds a robust drilling inventory that will be immediately integrated into our existing plans. The merger is expected to be completed in the second quarter of 2012 and allows for Cordillera to acquire up to $100 million in additional leasehold acreage in the Granite Wash and other plays through closing.

With the recent completed and pending acquisitions, the region plans to double its activity in 2012. The region plans to invest approximately $800 million in drilling, recompletions, equipment upgrades, production enhancement projects, and lease acquisitions.

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Permian Region Our Permian region controls over three million gross acres with exposure across the Permian Basin. The region s property and acreage base increased substantially after completing the 2010 BP acquisition and Mariner merger, and integrating these assets was a key focus during 2011. Apache is now one of the largest operators in the Permian Basin, operating more than 12,000 wells in 152 fields, including 45 waterfloods and six CO2 floods. Total region production was up over 38 percent sequentially as a result of the prior-year acquisitions and a drilling program that is continuing to ramp up. We averaged running 25 rigs during the year, drilling or participating in 507 wells. Only two dry holes were drilled, including a non-operated well. The Permian region s year-end 2011 estimated proved reserves were 751 MMboe and represent 25 percent of Apache s total proved reserves.

The key focus areas of our activity during the year continued to be the horizontal redevelopment of legacy waterflood units and the multi-zone development of the Deadwood area. Deadwood is the most active of our plays in the Permian Basin where we ran an average of 11 rigs and drilled 195 wells. Gross oil production in Deadwood exceeded 8 Mb/d and 17 MMcf/d at the end of the year, which compares with 2 Mb/d and 6 MMcf/d at the beginning of the year. Our gas volumes plateaued in this area in the fourth quarter because of midstream constraints. In order to increase capacity in 2012, the region began construction in the third-quarter 2011 on a natural gas processing facility in a 50-percent joint venture with Crosstex Energy, L.P. We expect to drill over 300 wells in Deadwood during 2012, and we have an inventory of approximately 1,000 additional vertical locations across multiple formations and stacked pay zones on 20-acre spacing.

Apache continued horizontal redevelopment of its waterflood units during 2011 with the drilling of 38 operated horizontal wells. Seven fields were tested with a 100-percent success rate. Three of these fields are under full horizontal development with the remaining fields in the testing phase. The region has identified an additional 23 major waterflood units and fields to be developed horizontally.

The Permian region is building a large inventory of other horizontal opportunities based on success achieved during 2011 along with the continued integration of the prior year BP acquisition and Mariner merger. As we head into 2012, the Company continues to advance several plays, including Bone Springs, Wolfcamp Shale, Cline Shale, and off-structure Grayburg formations. Given a current inventory of over 10,000 locations, the region has a strong portfolio of drilling opportunities for multiple years. For 2012, the Permian region plans to invest approximately $1.7 billion in drilling, recompletion projects, equipment upgrades, expansion of existing facilities and equipment, and leasing new acreage.

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 client 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. The 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 Apache has 7.5 million gross acres across the provinces of British Columbia, Alberta, and Saskatchewan. Our acreage base provides a significant inventory of both low-risk development drilling opportunities in and around a number of Apache fields and higher-risk, higher-reward exploration opportunities. At year-end 2011, our Canadian region represented approximately 26 percent of our estimated proved reserves. In 2011, we drilled or participated in 143 wells in Canada.

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Our conventional oil assets comprise a wide variety of opportunities from Southeast Saskatchewan to Northwest Alberta. An increased focus on these assets during 2011 resulted in drilling 70 wells, enabling us to take advantage of current strong oil price realizations. We utilized advanced reservoir modeling and horizontal drilling technology to identify and exploit unswept oil in existing waterflood projects in the House Mountain, Leduc, Snipe Lake, and Provost areas. Additionally, we continued efforts on our enhanced oil recovery project at Midale with expansion of CO2 injection and assessment of new seismic data.

In the Kaybob and West 5 areas, the region continues to have success in the development of liquids-rich natural gas plays. These areas have focused primarily on the Bluesky, Montney, and Glauconite formations through horizontal drilling and multi-stage fracture completions. In addition, drilling costs have been driven down throughout the year. Horizontal oil plays in the Viking, Dunvegan, and Cardium formations are emerging, and we expect to further develop these opportunities as part of our 2012 drilling program.

The region s near-term natural gas drilling activity will likely be focused in three large growth plays in British Colombia: shale gas in the Horn River basin, Cadomin conglomerates and sands in the Noel area, and fractured reservoirs in the Ojay area. Drilling activity focused on natural gas will be driven by investment decisions surrounding Apache s ownership in the Kitimat LNG facility. Apache Canada Ltd., Encana Corporation, and EOG Resources Canada, Inc. plan to build the Kitimat LNG facility on Bish Cove near the Port of Kitimat, 400 miles north of Vancouver, British Columbia. The facility is planned for an initial minimum capacity of 700 MMcf/d, or approximately five million metric tons of LNG per year, of which Apache has reserved 40 percent. A proposed 287-mile pipeline will also be constructed that will originate in Summit Lake, British Columbia, and is designed to link the Kitimat LNG facility to the pipeline system currently servicing western Canada s natural gas producing regions. Significant progress was made throughout the year to advance the LNG project. In October 2011, Apache and its partners in the Kitimat LNG project announced that the National Energy Board granted the project a 20-year export license to ship LNG from Canada to international markets. This export approval represents a major milestone for Kitimat LNG and its partners. In addition, the Company progressed with the FEED study and continued efforts to secure firm sales commitments and required permits necessary to make a final investment decision on the LNG project.

In 2012, the Canadian region plans to drill 170 wells, investing approximately $700 million in drilling and development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

Marketing Our Canadian natural gas marketing activities focus on sales to LDCs, utilities, end-users, integrated major oil companies, supply aggregators, and marketers. We maintain a diverse client portfolio, which is intended to reduce our concentration of credit risk in our portfolio. To diversify our market exposure, we transport natural gas via firm transportation contracts to 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 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 from Western Canada to the market hubs in Alberta and Manitoba, which allows 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 2011, international assets contributed 45 percent of our production and 54 percent of our oil and gas revenues. At year-end 2011, 31 percent of our estimated proved reserves were located outside North America.

Egypt

Overview Our commitment to 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 217 Mb/d and 865 MMcf/d in 2011, or 104 Mb/d and 365 MMcf/d net to Apache. We believe this makes Apache the largest producer of liquid hydrocarbons and natural gas in the Western Desert and the third largest in all of Egypt. The remaining 82 percent of our acreage is undeveloped, providing us with considerable exploration and development opportunities for the future. We have 3-D seismic covering over 12,000 square miles, or 78 percent of our acreage. In 2011, the region contributed 29 percent of Apache s worldwide production revenue, 22 percent of our worldwide production, and 10 percent of our year-end 2011 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 24 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.

Apache s Egyptian operations continue to expand further into the Western Desert and achieved a record for annual production in 2011. Compared to the prior year, gross daily production was up 12 percent, and net daily production was up two percent. Throughout 2011, we maintained an active drilling and development program, drilling 221 exploration, development, and injector wells, resulting in 33 new field discoveries. Most notably, we drilled the first Paleozoic discovery at Tayim West, which test-flowed at 3,600 b/d. This Paleozoic discovery opens a new play deeper than previous discoveries in the Western Desert and provides for continued exploration opportunities. We also made our first discovery in the Siwa Concession, our westernmost concession in Egypt, with the Siwa D-1X well that test-flowed at 4,490 b/d and 8 MMcf/d.

Building on prior year discoveries, we continued our drilling success in the Faghur basin having ten new field discoveries in the year that tested in aggregate over 33 Mb/d and 25 MMcf/d. These wells are the most recent in a series of oil discoveries in the Alam El Buieb (AEB), Safa, and now Paleozoic reservoirs that support the multi-pay potential of the oil prone basin. We also started to actively drill on acreage acquired in the 2010 BP acquisition. We drilled 21 successful wells on this acreage and have increased gross production by over 7 Mb/d and 39 MMcf/d. In addition to the increased drilling activity, we continue to assess opportunities to leverage existing processing and transportation infrastructure at the BP-acquired Abu Gharadig field complex and expand our processing facilities in the Faghur and Matruh basins. Maintaining and increasing infrastructure capacity is a critical component to our growth goals in the Western Desert.

Heading into 2012, the region plans to invest approximately $1.0 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition. Our drilling program includes a combination of development and exploration wells with current plans to drill approximately 20 percent more wells than in 2011.

Egypt political unrest In February 2011, former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power. In November 2011, Egypt held its first round of parliamentary elections. Despite the Muslim Brotherhood s Freedom and Justice Party s victory in the parliamentary elections, Egypt remains under martial law. Although Egypt s first post-revolutionary parliament convened on January 23, 2012, the new Parliament remains subordinate to the Egyptian Supreme Council of the Armed Forces, which has stated its intention to turn over power to civilians following the presidential election

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expected in June 2012. Apache s operations, located in remote locations in the Western Desert, have continued uninterrupted; 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 its investments in Egypt. In the aggregate, these 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 $237.5 million sub-limit for currency inconvertibility. In addition, the Company has a separate policy with OPIC, which provides $225 million of coverage, including a self-insured retention of $37.5 million, 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 when actions taken by the government of Egypt prevent Apache from exporting our share of production.

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, which corresponds to a Dated Brent price of $21.00 per barrel. Generally, this industry-pricing formula applies to all new gas discovered and produced. In exchange for extension of the Khalda Concession lease in July 2004, Apache 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 $4.66 per Mcf in 2011.

Oil from the Khalda Concession, the Qarun Concession and other nearby Western Desert blocks is sold primarily to third parties in the Mediterranean market or to EGPC when called upon to supply domestic demand. Oil sales are made either directly into the Egyptian oil pipeline grid, sold to non-governmental third parties including those supplying the Middle East Oil Refinery located in northern Egypt, or 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.

Australia

Overview Apache s holdings in Australia are focused offshore Western Australia in the Carnarvon basin, where we have operated since acquiring the gas processing facilities on Varanus Island and adjacent producing properties in 1993, in the Exmouth basin and in the Browse basin. Production operations are located in the Carnarvon and Exmouth basins. In total, we control approximately 8.8 million gross acres in Australia through 35 exploration permits, 16 production licenses, and 10 retention leases. Approximately 90 percent of our acreage is undeveloped.

During 2011, the region had net production of 38 Mb/d of oil and 185 MMcf/d of natural gas, contributing 10 percent of Apache s worldwide production revenue, 9 percent of worldwide production and 11 percent of year-end estimated proved reserves. Production compared to the prior year was 13 percent lower as a result of numerous tropical cyclones, repairs to the Floating Production Storage and Offloading vessel (FPSO) that services our Van Gogh oil field, and natural decline in the Pyrenees and Van Gogh oil fields.

Offsetting production declines was the start-up of two new developments offshore Western Australia. In June 2011, Apache s Halyard-1 gas discovery well commenced production into the domestic gas market. The Halyard development, which largely utilized existing Apache-operated pipelines and facilities, was completed ahead of schedule and set the stage for further development of our nearby Spar field. The region also completed development of the Reindeer gas field and construction of the Devil Creek Gas Plant in December. 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 current realizations.

The region also drilled several significant exploration and development wells in 2011. We participated in drilling nine wells during 2011, of which five were productive. Ongoing exploration activity at Apache s Julimar and Brunello complex resulted in the discovery of a deeper Mungaroo gas pool encountering 362 feet of net pay. This 65-percent working interest Balnaves Deep well is associated with continuing field development efforts and augments previous discoveries. Separately, the Zola-1 natural gas discovery logged 410 feet of net pay and is on trend with the Gorgon gas field 16 miles to the north and near both existing and developing infrastructure. The evaluation of this 30-percent working interest discovery, including the planning of future appraisal drilling, is currently underway.

In addition, the region has a pipeline of projects that are expected to contribute to production growth as they are brought on-stream over coming years.

The 2010 Spar-2 discovery is projected to commence production in 2013 through an extension of the Halyard subsea infrastructure, which will also allow for the tie-in of future wells.

First production is also projected in 2013 from four completed gas wells in the Macedon gas field. We have a 29-percent non-operating working interest in the field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant to be built at Ashburton North in Western Australia. The project, approved in 2010, is currently underway. Apache has successfully marketed nearly all of its proved reserves in the Macedon field under long-term contracts.

In 2011, the Coniston oil field project, which lies just north of the Van Gogh field, was sanctioned for development. First production is projected for 2013. The field will be produced via subsea completions tied back to the 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.

The region will also proceed with 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.

During 2011, the Company and its partners announced they will proceed with the Chevron-operated Wheatstone LNG development 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 2016.

These development projects require significant capital investments above traditional drilling programs. During 2012, the region plans to invest approximately $1.8 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition. Approximately 75 percent of the 2012 investment will be for development and processing facilities in connection with the projects discussed above.

In February 2012, a subsidiary closed on the acquisition of a 49-percent interest in Burrup Holdings Limited, which owns an ammonia plant on the Burrup Peninsula of Western Australia. Apache has been supplying natural gas to this plant since it commenced operations in 2006. This acquisition allowed Apache to stabilize the overall plant project, which was in receivership. The plant, which has been rebranded Yara Pilbara, has a production capacity of 760,000 mtpa and is one of the world s largest ammonia production facilities.

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, 2011, Apache had 22 active gas contracts in Australia with expiration dates ranging from November 2012 to December 2026. Recent increases in demand and higher development costs have increased the supply 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 NYMEX oil prices.

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. Forties, which Apache acquired with 45 producing wells, now has 75 producing wells with a substantial inventory of future drilling locations.

In 2011, the North Sea region produced 20 MMboe of which approximately 99 percent was crude oil. The region represents seven percent of our total worldwide production and 13 percent of Apache s oil and gas production revenues. In 2011, the region s production decreased four percent compared to the prior year as natural well decline and unplanned maintenance downtime exceeded gains from drilling. The drilling program, however, was successful and benefited greatly from a new 4-D seismic interpretation derived from the latest 3-D seismic survey acquired over Forties in 2010. The data highlighted many areas of bypassed oil in the reservoir and provided better definition of existing targets. In 2011, 14 wells were drilled in Forties, of which 11 were productive. Two of the highest producing wells were the Charlie 4-3 well, which commenced production in June at a rate of 12.6 Mb/d, and the Charlie 2-2 well, which was completed in March with an initial rate of 11.9 Mb/d. These rates were some of the highest in the Forties since 1990.

In addition, the region acquired an 11.5 percent non-operated interest in the Nelson field in early 2011, and on December 30, 2011, closed on the acquisition of Mobil North Sea Limited from Exxon Mobil Corporation. The assets acquired include operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields; operated interest in the Beryl/Brae gas pipeline and the SAGE gas plant; non-operated interests in the Maclure, Scott, and Telford fields; and Benbecula (west of Shetlands) exploration acreage. These major legacy assets bring the region quality reservoirs with significant remaining reserve life, high production efficiency, and a portfolio of low-risk exploitation projects. Beginning in 2012, production from the former Mobil North Sea fields will add to the percentage of Apache s current output that is indexed to the premium Brent crude oil benchmark price. These acquisitions expand Apache s presence in the North Sea and increase its portfolio of future drilling locations.

Estimated proved reserves recorded at the end of the year for the acquired properties totaled 61 MMboe, bringing Apache s total estimated proved reserves at year-end 2011 to 197 MMbbls of crude oil in this region, or approximately seven percent of our worldwide year-end estimated proved reserves.

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In 2012, the region will invest approximately $950 million on a diverse set of capital projects. Forties will see another year of active drilling with two platform rigs operating the entire year along with a partial year of jack-up drilling at the Echo platform. Construction of the Forties Alpha Satellite Platform is underway and is projected to be complete by the third quarter of 2012. This platform will sit adjacent to the main Alpha platform and provide an additional 18 drilling slots along with power generation, fluid separation, gas lift compression, and oil export pumping. The region will also work to integrate the acquired Mobil North Sea properties and plans to drill three wells on these properties during the year along with well recompletions and workovers.

Marketing We have traditionally sold our Forties crude under both term contracts and spot cargoes. The term sales are composed of a market-based index prices 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. All 2012 production from Forties will be sold under a term contract with a per-barrel premium to the Dated Brent index. Production from the former Mobil North Sea fields will also be indexed to the premium Brent crude oil benchmark price.

Argentina

Overview We have had a continuous presence in Argentina since 2001, which was expanded substantially by two acquisitions in 2006. We currently have operations in the Provinces of Neuquén, Rio Negro, Tierra del Fuego, and Mendoza. We have interests in 34 concessions, exploration permits, and other interests totaling 3.7 million gross acres in four of the main Argentine hydrocarbon basins: Neuquén, Austral, Cuyo, and Noroeste. Our concessions have varying expiration dates ranging from three years to over 15 years remaining, subject to potential extensions. In 2011, Argentina produced six percent of our worldwide production and held four percent of our estimated proved reserves at year-end.

In 2011, the region achieved record production of 48 Mboe/d and drilled 36 gross wells pursuant to a development drilling program that achieved a 97 percent success rate by focusing on unconventional premium gas and shallow oil targets. Our exploration program included drilling six gross wells in 2011. We are continuing to test two vertical wells targeting the Vaca Muerta formation in the Huacalera and Cortadera areas and are targeting oil in two recent exploration wells drilled in the Cuyo basin.

During the year, Apache s first horizontal well in the Anticlinal Campamento field in the Neuquén basin began producing at a rate over 10 MMcf/d. The well was a test of horizontal drilling and multi-stage hydraulic fracturing in the low-permeability pre-Cuyo formation. In the third quarter, we completed the first horizontal multi-stage hydraulically fractured shale gas well drilled and completed in South America. The region will continue to evaluate the use of horizontal drilling techniques on tight and unconventional gas resources in the pre-Cuyo, Los Molles, and Vaca Muerta formations of the Neuquén basin, as these formations receive the benefit of higher gas prices under the Gas Plus program, as defined below.

Apache added acreage during the year in the Neuquén and Noroeste basins, increasing the region s unconventional oil and gas potential. We also began negotiations for extensions of 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.

During 2012, the region plans to invest approximately $250 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

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Marketing

Natural Gas Apache sells its natural gas 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 2011, the average Gas Plus volume sold by Apache was 55.1 MMcf/d at an average price of $4.89 per Mcf. In addition, Apache signed or extended Gas Plus contracts with industrial consumers totaling gross rates of 15.5 MMcf/d at $4.28 per Mcf through December 31, 2012.

Government-regulated pricing: The volumes we are required to sell at regulated prices are set by the Argentine government and vary with seasonal factors and industry category. During 2011, we realized an average price of $1.06 per Mcf on government-regulated sales.

Unregulated market: The majority of our remaining volumes are sold into the unregulated market. In 2011, realizations averaged $3.14 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. In Tierra del Fuego, similar pricing formulas exist; however, Apache retains the value-added tax collected from buyers, effectively increasing realized prices by 21 percent. As a result, 2011 oil prices realized from Tierra del Fuego oil production averaged $76.51 per barrel as compared to our Neuquén basin production, which averaged $64.16 per barrel.

Other Exploration

New Ventures

Apache continues to pursue numerous exploration opportunities in new areas across the globe. In Cook Inlet, Alaska, where we are currently the largest acreage holder with approximately 800,000 gross acres, we plan to conduct a seismic survey and drill a well within the next 12 months. During 2012, we also plan to drill a well in deepwater Kenya, where we hold a 50-percent working interest and are the operator. In the East Coast basin of New Zealand, where we have entered into a farm-in agreement to explore and potentially develop about 1.7 million gross acres, we expect to commence seismic operations and drill our first four wells targeting new onshore unconventional oil plays during 2012. Apache will earn a 50-percent interest in the New Zealand exploration permits upon completing the seismic and drilling program planned for the next four years.

During 2012, we plan to invest approximately $450 million to pursue exploration opportunities in new areas where Apache has yet to establish an operating region.

Chile

In November 2007, Apache was awarded exploration rights on two blocks comprising approximately one million net acres on the Chilean side of Tierra del Fuego. Upon careful evaluation of the exploration potential and economics of the blocks, we determined that these blocks are no longer prospective to Apache. As such, in the fourth quarter of 2011, we relinquished this acreage and recorded a $60 million non-cash write-off of the carrying value of our oil and gas property balance in Chile.

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Major Customers

In 2011, 2010, and 2009, purchases by Royal Dutch Shell plc and its subsidiaries accounted for 11 percent, 15 percent, and 18 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 2011 we participated in drilling 1,087 gross wells, with 1,005 (92 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 exploitation wells. In addition to our completed wells, at year-end several wells had not yet reached completion: 39 in the U.S. (28.44 net); 50 in Canada (42.69 net); 23 in Egypt (21.75 net); 6 in the North Sea (4.91 net); 1 in Australia (0.33 net); and 3 in Argentina (3.00 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
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
2009									
United States	5.6	2.5	8.1	107.6	8.5	116.1	113.2	11.0	124.2
Canada	3.0		3.0	136.8	12.8	149.6	139.8	12.8	152.6
Egypt	8.6	10.4	19.0	126.4	4.0	130.4	135.0	14.4	149.4
Australia	6.9	3.8	10.7	4.7		4.7	11.6	3.8	15.4
North Sea	1.0		1.0	12.6	2.9	15.5	13.6	2.9	16.5
Argentina	3.4	0.7	4.1	25.5		25.5	28.9	0.7	29.6
Other International	2.0		2.0				2.0		2.0
Total	30.5	17.4	47.9	413.6	28.2	441.8	444.1	45.6	489.7

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, 2011, is set forth below:

	Oil		Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	12,667	8,465	4,936	2,899	17,603	11,364
Canada	2,210	1,015	9,390	8,015	11,600	9,030
Egypt	880	839	80	76	960	915
Australia	44	20	12	7	56	27
North Sea	147	97	24	11	171	108
Argentina	465	390	470	440	935	830
Total	16,413	10,826	14,912	11,448	31,325	22,274

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Gross natural gas and crude oil wells include 1,675 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 Lease Operating Cost per Boe	Average Sales Price		
Year Ended December 31,	Oil (MMbbls)	NGLs (MMbbls)	Gas (Bcf)		Oil (Per bbl)	NGLs (Per bbl)	Gas (Per Mcf)
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	66.36	4.66
Australia	14.0		67.6	7.80	111.22	65.45	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	69.75	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
2009							
United States	32.5	2.2	243.1	$ 10.59	$ 59.06	$ 33.02	$ 4.34
Canada	5.5	0.8	131.1	11.46	56.16	25.54	4.17
Egypt	33.6		132.3	5.17	61.34		3.70
Australia	3.6		67.0	6.84	64.42		1.99
North Sea	22.3		1.0	8.19	60.91		13.15
Argentina	4.2	1.2	67.4	6.78	49.42	18.76	1.96
Total	101.7	4.2	641.9	8.48	59.85	27.63	3.69

Gross and Net Undeveloped and Developed Acreage

The following table sets out our gross and net acreage position in each country where we have operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
United States	5,323,494	3,057,334	4,975,556	2,555,355
Canada	3,084,789	2,640,389	4,433,557	3,355,367
Egypt	7,944,459	5,151,927	1,784,630	1,661,556
Australia	7,945,004	4,684,742	861,400	488,470
North Sea	598,091	251,525	187,462	85,904

Argentina	3,519,906	2,872,880	220,840	188,226
Total	28,415,743	18,658,797	12,463,445	8,334,878

As of December 31, 2011, we had 4,198,666, 3,772,074, and 1,885,448 net acres scheduled to expire by December 31, 2012, 2013, and 2014, respectively, if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licenses and concession areas through operational or administrative actions and do not project a significant portion of our net acreage position to expire before such actions occur.

As of December 31, 2011, 34 percent of U.S. net undeveloped acreage and 40 percent of Canadian undeveloped acreage was held by production.

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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.

PUD 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, 2011, based on average commodity prices in effect on the first day of each month in 2011, 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	428	107	2,216	905
Canada	82	23	2,109	457
Egypt	106		701	223
Australia	36		676	148
North Sea	137	9	105	163
Argentina	16	6	447	96
Proved Undeveloped:				
United States	206	53	760	385
Canada	60	8	1,439	308
Egypt	22		282	69
Australia	32		894	181
North Sea	32	1	3	34
Argentina	5	1	90	21
TOTAL PROVED	1,162	208	9,722	2,990

As of December 31, 2011, Apache had total estimated proved reserves of 1,370 MMbbls of crude oil, condensate, and NGLs and 9.7 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 3.0 billion barrels of oil or 17.9 Tcf of natural gas, of which oil represents 39 percent. As of December 31, 2011, the Company s proved developed reserves totaled 1,992 MMboe and estimated PUD reserves totaled 998 MMboe, or approximately 33 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, 2011, 2010, and 2009, 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, 2011 and 2010, 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 998 MMboe as of December 31, 2011, increased by 30 MMboe over the 968 MMboe of PUD reserves estimated at the end of 2010. During the year, Apache converted 106 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America, we converted 78 MMboe, with the remaining 28 MMboe in our international areas. We divested 12 MMboe of PUD reserves during the year primarily associated with our East Texas sales package. We acquired 6 MMboe of PUD reserves during the year. We added 179 MMboe of new PUD reserves through extensions and discoveries and had revisions of (37) MMboe associated with changes in product prices and revised development plans.

During the year, a total of approximately $2.6 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2010. 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 $1.4 billion on PUD reserve development activity in North America and $1.2 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, 2011.

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 centralized and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable.

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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 2011, the properties selected for each country ranged from 57 to 100 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 81 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 70 percent of total proved reserves, including 76 percent of proved developed reserves and 59 percent of PUD reserves. Properties with PUD reserves generally have an associated capital expenditure required to develop those reserves included in their net present value calculation, reducing their value relative to proved developed reserves. For this reason those properties are less likely to be selected for the audit, resulting in a higher percentage review coverage for proved developed reserves.

During 2011, 2010, and 2009, Ryder Scott s review covered 81, 72, and 79 percent, respectively, of the Company s worldwide estimated proved reserves value and 70, 63, and 69 percent, respectively, of the Company s total proved reserves volume. 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. Ryder Scott s review of 2009 covered 66 percent of U.S., 48 percent of Canada, 63 percent of Argentina, 96 percent of Australia, 86 percent of Egypt, and 80 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, 2011, we had 5,299 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 2011, 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. 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.

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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), adopted certain Region 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. Periodically, 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 (CGA, described below), and representatives of governmental agencies. The primary association available to Apache and ADW in the event of a spill is CGA. Apache and ADW have received approval for the Plans from the Bureau of Ocean Energy Management (BOEM). Apache and ADW personnel each review their respective Plan annually and update where necessary.

Both Apache and ADW are members of, and Apache has an employee representative on the executive committee of, 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. To this end, CGA has bareboat chartered (an arrangement for the hiring of a boat with no crew or provisions included) its marine equipment to 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. MSRC maintains CGA s equipment (currently including 13 shallow water skimmers, four fast response vessels with skimming capabilities, nine fast response containment-skimming units, a large skimming containment barge, numerous containment systems, wildlife cleaning and rehabilitation facilities, and dispersant inventory) at various staging points around the Gulf of Mexico in its ready state, and in the event of a spill, MSRC stands ready to mobilize all of this equipment to CGA members. MSRC also handles the maintenance and mobilization of CGA non-marine equipment. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies. In 2011, we incurred charges for CGA of approximately $300,000: $12,800 per member and a fee based on 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, which entitles any Apache entity worldwide to access their service. Oil Spill Response Limited has access to resources from the Global Response Network, a collaboration of seven major oil industry funded spill response organizations worldwide. Oil Spill Response Limited 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, Oil Spill Response Limited s resources may be, and have been, deployed to areas across the globe, such as the Gulf of Mexico. In addition, in February 2012, ADW became a member of MSRC and National Response Corporation (NRC), and such resources are available to ADW for its deepwater Gulf of Mexico operations along with the spill response resources of other organizations, each of which are 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, currently including 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, seven 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 these companies changes from time to time, and current information is generally available on each of the companies websites.

In 2011, ADW 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 2011 membership dues for the two-year service agreement were approximately $1.4 million.

In 2011, ADW also became a member of the Marine Well Containment Company (MWCC) to fulfill the government permit requirements for containment and oil spill response plans in deepwater Gulf of Mexico operations. 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 2012. 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 BOEM requirements. The system is designed to operate in 10,000 feet of water and process up to 100,000 b/d and 200 MMcf/d. The current interim system can operate in water depths up to 8,000 feet and has storage and processing capacity for up to 60,000 b/d. Membership in MWCC is open to all companies operating in the U.S. Gulf of Mexico. Members 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. In 2011, ADW paid $40 million to MWCC, which represents our initial capital investment.

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 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, 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.

Changes to existing, or additions of, laws, regulations, enforcement policies or requirements in one or more of the countries or regions in which we operate could require us to make additional capital expenditures. While the events in the U.S. Gulf of Mexico in 2010 have resulted in the enactment of, and may result in the enactment of additional, laws or requirements regulating the discharge of materials into the environment, we do not believe that any such regulations or laws enacted or adopted as of this date will have a material adverse impact on our cost of operations, earnings, or competitive position.

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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. There are likely to be significant long-term effects resulting from the recession and credit market crisis, 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 a sustainable, yet lower, 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.

In addition, the Organisation for Economic Co-operation and Development (OECD) has encouraged countries with large federal budget deficits to initiate deficit reduction measures. As a result of the European sovereign debt crisis, certain European countries have initiated austerity measures. Such deficit reduction measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand.

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 2011 ranged from a high of $113.93 per barrel to a low of $75.67 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2011 ranged from a high of $4.85 per MMBtu to a low of $2.99 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;

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- 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:

- drilling well blowouts, explosions, and cratering;

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- pipeline ruptures and spills;
- fires;
- formations with abnormal pressures;
- equipment malfunctions; and
- 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.

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, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture 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.

The Devon and Mariner transactions have increased our exposure to Gulf of Mexico operations.

Our 2010 acquisitions of oil and gas assets in offshore Gulf of Mexico from Devon Energy Corporation and Mariner Energy, Inc. have increased our exposure to offshore Gulf of Mexico operations. Greater offshore concentration proportionately increases risks from delays or higher costs common to offshore activity, including severe weather, availability of specialized equipment and compliance with environmental and other laws and regulations.

In addition, regulatory changes in the Gulf of Mexico after the Deepwater Horizon incident and the increased demand for drilling rigs and oilfield services since the resumption of activities in the Gulf may lead to higher costs and reduced availability of such rigs and services, making satisfactory returns on our investments in that region more difficult to achieve.

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 US Department of the Interior, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), now split into 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 requirements applicable to drilling activities in the Gulf of Mexico, 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. In addition, the U.S. Department of the Interior (or BOEM/BSEE) requires that operators demonstrate their compliance with new regulations before they resume deepwater drilling. While certain new drilling plans and drilling permits have been approved during 2011, we cannot predict when development and production activities will return to previous levels of activity in the Gulf of Mexico.

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

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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 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;

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- 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.

Several significant matters in the BP Acquisition were not resolved before closing.

Because of the relatively short time period between signing the BP Purchase Agreements and the closing of the acquisition of the BP properties, several significant matters commonly resolved prior to closing such an acquisition were reserved for after closing. We did not have sufficient time before closing on the BP Properties to conduct a full environmental assessment. We may discover adverse environmental or other conditions after closing and after the time periods specified in the BP Purchase Agreements during which we may be able to seek, in certain cases, indemnification from or cure of the defect or adverse condition by BP for such matters. For example, Apache Canada Ltd. has asserted a claim against BP Canada arising from the acquisition of certain

Canadian properties under the BP Purchase Agreements. The dispute centers on Apache Canada Ltd. s identification of Alleged Adverse Conditions, as that term is defined in the BP Purchase Agreements, and more specifically, the contention that liabilities associated with such conditions were retained by BP Canada as seller. There can be no assurance that we will prevail on this or any future claim against BP.

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 BP Purchase Agreements 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 under current regulations the rates and amounts of payments are expected to increase. Quantifying our total net financial exposure to GHG taxes in Australia awaits regulatory guidance and clarification, but we expect the value to be manageable within the context of our ongoing 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 2013 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 13, 2012, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2013. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The 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.

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. In November 2011, Egypt held its first round of parliamentary elections. Despite the Muslim Brotherhood s Freedom and Justice Party s victory in the parliamentary elections, Egypt remains under martial law. The new Parliament remains subordinate to the Egyptian Supreme Council of the Armed Forces, which has stated its intention to turn over power to civilians following the presidential election expected in June 2012. 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 22 percent of our 2011 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2011, 17 percent of our estimated discounted future net cash flows and 7.5 percent of our net capitalized oil and gas property was attributable to Egypt.

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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 45 percent of our 2011 production was outside North America, and approximately 31 percent of our estimated proved oil and gas reserves on December 31, 2011 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

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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;
- 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

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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, 2011, 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.

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PART II

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

During 2011, 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 2011 and 2010. 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.

	2011				2010			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 132.50	$ 110.29	$ 0.15	$ 0.15	$ 108.92	$ 95.15	$ 0.15	$ 0.15
Second Quarter	134.13	114.94	0.15	0.15	111.00	83.55	0.15	0.15
Third Quarter	129.26	80.05	0.15	0.15	99.09	81.94	0.15	0.15
Fourth Quarter	105.64	73.04	0.15	0.15	120.80	96.51	0.15	0.15

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2012 (last trading day of the month), was $98.88 per share. As of January 31, 2012, there were 384,321,970 shares of our common stock outstanding held by approximately 5,600 stockholders of record and approximately 444,000 beneficial owners.

We have paid cash dividends on our common stock for 47 consecutive years through December 31, 2011. When, and if, declared by our Board of Directors, future dividend payments will depend upon our level of earnings, financial requirements, and other relevant factors.

In 1995, under our stockholder rights plan, each of our common stockholders received a dividend of one preferred stock purchase right (a right) for each 2.310 outstanding shares of common stock (adjusted for subsequent stock dividends and a two-for-one stock split) that the stockholder owned. These rights were originally scheduled to expire on January 31, 2006. Effective as of that date, the rights were reset to one right per share of common stock, and the expiration was extended to January 31, 2016. Unless the rights have been previously redeemed, all shares of Apache common stock are issued with rights, which trade automatically with our shares of common stock. For a description of the rights, please refer to Note 9 Capital Stock in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Information concerning securities authorized for issuance under equity compensation plans is set forth under the caption Equity Compensation Plan Information in the proxy statement relating to the Company s 2012 annual meeting of stockholders, which is incorporated herein by reference.

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The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company s common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company s common stock with the cumulative total return of the Standard & Poor s Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 31, 2006, through December 31, 2011. The stock performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

	2006	2007	2008	2009	2010	2011
Apache Corporation	$ 100.00	$ 162.91	$ 113.67	$ 158.58	$ 184.36	$ 140.80
S & P s Composite 500 Stock Index	100.00	105.49	66.46	84.05	96.71	98.76
DJ US Expl & Prod Index	100.00	143.67	86.02	120.92	141.16	135.25

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ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth selected financial data of the Company and its consolidated subsidiaries over the five-year period ended December 31, 2011, which information has been derived from the Company s audited financial statements. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in the Company s financial statements set forth in Part IV, Item 15 of this Form 10-K. As discussed in more detail under Item 15, the 2009 numbers in the following table reflect a $2.82 billion ($1.98 billion net of tax) non-cash write-down of the carrying value of the Company s U.S. and Canadian proved oil and gas properties as of March 31, 2009, as a result of ceiling test limitations. The 2008 numbers reflect a $5.3 billion ($3.6 billion net of tax) non-cash write-down of the carrying value of the Company s U.S., U.K. North Sea, Canadian, and Argentine proved oil and gas properties as of December 31, 2008.

	As of or for the Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In millions, except per share amounts)				
Income Statement Data					
Total revenues	$ 16,888	$ 12,092	$ 8,615	$ 12,390	$ 9,999
Income (loss) attributable to common stock	4,508	3,000	(292)	706	2,807
Net income (loss) per common share:					
Basic	11.75	8.53	(0.87)	2.11	8.45
Diluted	11.47	8.46	(0.87)	2.09	8.39
Cash dividends declared per common share	0.60	0.60	0.60	0.70	0.60
Balance Sheet Data					
Total assets	$ 52,051	$ 43,425	$ 28,186	$ 29,186	$ 28,635
Long-term debt	6,785	8,095	4,950	4,809	4,012
Shareholders equity	28,993	24,377	15,779	16,509	15,378
Common shares outstanding	384	382	336	335	333

For a discussion of significant acquisitions and divestitures, see Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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ITEM 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

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, offshore the United Kingdom in the 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 discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K, and the Risk Factors information set forth in Part I, Item 1A of this Form 10-K.

Executive Overview

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

A cornerstone of our strategy is balancing our portfolio through diversity of geologic risk, geographic risk, hydrocarbon mix (crude oil versus natural gas), and reserve life in order to achieve consistency in results. Continued volatility in the commodity price environment reinforces the importance of our balanced portfolio approach. Our 2011 results reflected the benefit of our product balance, as crude oil and liquids combined represented 50 percent of our production but provided 79 percent of our $16.8 billion of oil and gas revenues. Crude oil drove 92 percent of this combined crude and liquids production and 96 percent of the related revenues. International Dated Brent crudes and sweet crude from the Gulf Coast continue to be priced at a significant premium to West Texas Intermediate (WTI)-based prices. As a result of our geographic balance, we are receiving these premium prices on approximately 76 percent of our crude oil production. The advantage of our geographic balance is also reflected in our 2011 natural gas revenues. Over one-third of our natural gas is produced outside of North America, where 2011 prices averaged 27 percent higher than 2010. This balance allowed us to achieve record earnings and cash flow from operations for the year.

Preserving financial flexibility is also important to our overall business philosophy. We believe our balance sheet, and the financial flexibility it provides, is one of our most important strategic assets. It is also key in positioning us to pursue value-creating acquisitions when opportunities arise. During 2011, we reduced debt to $7.2 billion and ended the year with a debt-to-capitalization ratio of 20 percent, down from 25 percent at the end of 2010, despite current-year capital investments of $8 billion and cash payments on acquisitions totaling nearly $2 billion. In addition, we have $3.3 billion of available committed borrowing capacity that provides additional flexibility to our business. Our balance sheet strength, financial flexibility, and record levels of cash flow from operations provide a solid foundation as we continue to integrate recent acquisitions and monetize opportunities in all of our regions.

Each of our operating regions has a significant producing asset base as well as large undeveloped acreage positions, which provide room for growth through sustainable lower-risk drilling opportunities, balanced by higher-risk, higher-reward exploration. We closely monitor drilling and acquisition cost trends in each of our

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core areas relative to product prices and, when appropriate, adjust our budgets accordingly. We review capital allocations at least quarterly. We do this through a disciplined and focused process that includes analyzing current economic conditions, projected rate of return on internally-generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects, or, occasionally, new core areas that could enhance our portfolio. In addition, we actively seek to identify and pursue ways to maintain efficient levels of costs and expenses. Our overall approach to managing cash expenditures has enabled us to consistently deliver strong results with 2011 return on average capital employed and return on equity of 13 percent and 18 percent, respectively.

Throughout the cycles of our industry, these strategic principles have underpinned our ability to deliver production, reserve growth, and competitive returns on invested capital for the benefit of our shareholders. Delivering successful results under this strategy is bolstered by Apache s unique culture. A strong sense of urgency, empowerment of our employees, effective incentive systems, and an independent mindset are at the heart of how we build value.

Financial and Operating Results

Apache s steady commitment to our core strategies drove financial performance throughout 2011. For the 12-month period ending December 31, 2011, Apache reported record performances in several key metrics. Highlights for the year include:

- Annual daily production of oil, natural gas, and natural gas liquids averaged a record 748 Mboe/d, up 14 percent compared with 2010. Production in fourth-quarter 2011 averaged 759 Mboe/d, an increase of four percent from the 729 Mboe/d averaged in the fourth quarter of 2010.

- Oil and gas production revenues for 2011 increased 38 percent to $16.8 billion, up from $12.2 billion in 2010, well above our prior record of $12.3 billion achieved in 2008, when we also saw record prices.

- Apache reported a record $4.5 billion in income attributable to common stock, an increase of over 50 percent compared to $3 billion in 2010. Net income per diluted common share was $11.47 in 2011, up from $8.46 in 2010. Apache s reported adjusted earnings, which exclude certain items impacting the comparability of results, were $4.7 billion in 2011, an increase of 47 percent from $3.2 billion in 2010. Adjusted earnings per common diluted share were $11.83 in 2011, up from $8.94 in the prior year. Adjusted earnings is not a financial measure prepared in accordance with accounting principles generally accepted in the U.S. (GAAP). For a description of adjusted earnings and a reconciliation of adjusted earnings to income attributable to common stock, the most directly comparable GAAP financial measure, please see Non-GAAP Measures in this Item 7.

- Net cash provided by operating activities (operating cash flows or cash flows) totaled $10.0 billion, up 48 percent from $6.7 billion in 2010.

2012 Outlook

As we head into 2012, we believe our inventory of exploration and development projects offers numerous growth opportunities. Recent drilling successes and continued acquisition of acreage positions in all of our operating regions has built a robust drilling inventory for the Company. Coupled with large-scale development projects currently in progress, our global allocation of capital is critical. Given the present price disparity between oil and natural gas, our near-term focus is exploiting the oil-prone and more liquids-rich properties in our portfolio. Our plan for 2012 also includes development of our gas resources in Australia and Canada to supply our LNG projects, which, if completed, would enable us to monetize these resources at prices more closely linked to crude oil. Rate of return will drive our decision making while we continue our focus on costs, operational efficiency, and integrating recently acquired assets.

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Our current 2012 capital budget is approximately $9.5 billion. Nearly $5.3 billion is expected to be spent on projects in North America, with the remaining amount allocated across our international regions. While funds have been committed for certain 2012 exploration drilling, long-lead development projects, and front-end engineering and design (FEED) studies, the majority of our drilling and development projects are discretionary and subject to acceleration, deferral, or cancellation as conditions warrant. We closely monitor commodity prices, service cost levels, regulatory impacts, and numerous other industry factors, and we typically review and revise our exploration and development budgets based on changes to predicted operating cash flows on a quarterly basis.

Apache projects an increase in 2012 production between 7 percent and 13 percent from full-year 2011 production levels, after adjusting for 2011 divestitures. We generally do not budget for acquisitions because they are specific, discrete events whose occurrence and timing is unpredictable. Acquisitions may be funded from operating cash flows, credit facilities, new equity, debt issuances, or a combination thereof.

Operating Highlights

Apache pursues opportunities for growth through exploration, exploitation, and development drilling, supplemented by strategic acquisitions. In 2011, we generated $10 billion of cash flow from operations, which enabled us to deliver on a robust capital budget, investing approximately $8 billion in capital expenditures across all of our regions while paying down nearly $1 billion in debt. We have also been significantly active in the acquisition market for the past two years, having identified several opportunities that met our criteria for risk, reward, rate of return, and growth potential.

Merger and Acquisitions of Property and Acreage

During 2011 and 2010, we completed nearly $14 billion in acquisitions culminating in the purchase of Exxon Mobil Corporation s North Sea subsidiary, Mobil North Sea Limited. As we head into 2012, Apache continues to be active with recent acquisition announcements in Australia and the Anadarko basin of the central U.S. Each of our acquisitions fits well with our long-term strategy of maintaining a balanced portfolio of core assets by adding high-quality properties with a diversity of geologic and geographic risk, product mix, and reserve life. The properties acquired impacted nine of our ten operating regions and are strategically positioned to benefit from our existing infrastructure and operating experience. For detailed information regarding our recent acquisitions, please see Significant Acquisitions and Divestitures in this Item 7 and Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

2012 Acquisitions

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

Central Anadarko basin acquisition Apache announced in January 2012 that we agreed to acquire Cordillera Energy Partners III, LLC (Cordillera), a privately-held company, for approximately 6.3 million shares of Apache common stock and $2.2 billion in cash. The merger is expected to close during the second quarter of 2012.

2011 Acquisitions

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

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2010 Acquisitions

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

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.

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.

Exploration, Exploitation and Development Activities

Our internally-generated exploration and drilling opportunities, multi-year development projects, and recent acquisitions provide the foundation for our growth in the near- and long-term. Highlights of our 2011 drilling successes, exploration discoveries, LNG project milestones, and other opportunities for continued growth include:

International Activities

North Sea Drilling and Exploitation New 4-D seismic interpretation derived from the latest 3-D seismic survey acquired over the Forties field in 2010 highlighted areas of bypassed oil. During 2011, we drilled 14 wells, of which 11 were productive. The Charlie 4-3 well commenced production in June at a rate of 12,567 b/d, and the Charlie 2-2 well was completed in March with an initial rate of 11,876 b/d. These wells represent some of the highest rates in the Forties field since the early 1990s.

North Sea Satellite Platform Project Construction of the Forties Alpha Satellite Platform is underway and is projected to be complete by the third quarter of 2012. This platform will sit adjacent to the main Alpha platform and will provide Apache with 18 new slots for drilling additional development wells to increase the ultimate recovery from the Forties field. The satellite platform will also expand critical utility services to the field, including power generation, produced fluid processing, high-pressure gas compression for artificial lift and dehydration.

Egypt Discoveries Apache s Egyptian operations continue to expand further into the Western Desert and achieved a record for annual production in 2011. We maintained an active drilling and development program throughout 2011, drilling 221 exploration, development, and injector wells, resulting in 33 new field discoveries. Most notably, we drilled the first Paleozoic discovery at Tayim West, which test-flowed at 3,600 b/d. This Paleozoic discovery opens a new play deeper than previous discoveries in the Western Desert and provides for continued exploration opportunities. We also made our first discovery in the Siwa Concession, our western-most concession in Egypt, with the Siwa D-1X well that flowed at 4,490 b/d and 8 MMcf/d. In addition to increased drilling activity, we continue to assess opportunities to leverage existing processing and transportation infrastructure at the BP-acquired Abu Gharadig field complex and expand our processing facilities in the Faghur and Matruh basins.

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Argentina Exploration Apache s first horizontal well in the Anticlinal Campamento field in the Neuquén basin began producing at a rate over 10 MMcf/d. The well was a test of horizontal drilling and multi-stage hydraulic fracturing in the low-permeability Pre-Cuyo formation. Apache continues to evaluate the potential of tight and unconventional gas resources in the Pre-Cuyo, Los Molles, and Vaca Muerta formations of the Neuquén basin, which is supported by higher gas prices realized under the Gas Plus program. In 2011, the average Gas Plus volume sold by Apache was 55.1 MMcf/d at an average price of $4.89 per Mcf.

Australia Exploration Ongoing exploration activity at the Julimar and Brunello complex resulted in the discovery of a deeper Mungaroo gas formation encountering 362 feet of net pay. This 65-percent working interest Balnaves Deep well is associated with continuing field development efforts and augments previous discoveries. Separately, the Zola-1 natural gas discovery logged 410 feet of net pay and is on trend with the Gorgon gas field 16 miles to the north and near both existing and developing infrastructure. The evaluation of the 30-percent working interest discovery, including the planning of future appraisal drilling, is underway.

Australia Reindeer Field Development and Devil Creek Gas Plant Development of our Reindeer gas field and construction of the Devil Creek Gas Plant was completed in December 2011. Gas production from the Reindeer development has been sold to a number of customers in Western Australia s growing mining and minerals processing sectors at prices significantly higher than current realizations. Apache owns a 55-percent interest in the field and is the operator.

Australia Halyard Field Development Initial production from our Halyard-1 discovery well commenced in June 2011 upon completion of the tie-in to the existing gas facilities on Varanus Island. The Halyard development was completed ahead of schedule and set the stage for further development of our nearby Spar field. The 2010 Spar-2 discovery is projected to commence production in 2013 through an extension of the Halyard subsea infrastructure that will also allow for the tie-in of future wells.

Australia Macedon Field Development First production is also projected in 2013 from four completed gas wells in the Macedon gas field. We have a 29-percent non-operating working interest in the field. Gas will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant to be built at Ashburton North in Western Australia. The project, approved in 2010, is currently underway.

Australia Coniston Oil Field Development The Coniston field is an oil accumulation near our Van Gogh field in Australia. The project was sanctioned for development in 2011 with first production projected in 2013. Apache operates the field with a 52.5-percent working interest and expects peak production to be approximately 30 Mb/d. The field will be produced via subsea completions tied back to the Ningaloo Vision floating production storage and offloading vessel (FPSO) that services Apache s Van Gogh oil field. To more effectively control the Van Gogh and Coniston field operations, development, and maintenance efforts, this FPSO (the Ningaloo Vision) was purchased from the previous lessor in January 2012 for $185 million, $97 million net to Apache.

Australia Balnaves Oil Development In 2011, the Company announced that it will proceed with development of the offshore Balnaves field, an oil accumulation located in a separate reservoir within the large gas reservoirs of our Brunello gas fields. The project is expected to deliver initial gross production of 30 Mb/d in 2014 through a leased FPSO. Apache has a 65-percent working interest in the operated project.

Australia Wheatstone LNG Project During 2011, the Company and its partners announced they will proceed with the Chevron-operated Wheatstone LNG development 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, which was approved for development by the Australian government in September 2011. The 65-percent interest Julimar development project is expected to generate average net sales to Apache of

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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 2016.

North America Activities

Permian Basin Gas Plant Development During 2011, Apache agreed with Crosstex Energy, L.P. to jointly build an $85 million natural gas processing facility for our Deadwood development in the Permian Basin of west Texas. The plant, in which Apache has a 50-percent interest, is anticipated to become fully operational in the second quarter of 2012, with capacity of 50 MMcf/d. This infrastructure will enable Apache to continue its active development program targeting multiple stacked formations, including the Wolfcamp, Cline, Strawn, Atoka, and Fusselman.

North America Horizontal Drilling Apache continues to evaluate horizontal drilling potential across our acreage positions, in both conventional and unconventional reservoirs. In the Permian Basin, Apache is utilizing horizontal drilling to access bypassed, unswept oil zones in established waterfloods. The identification and development of significant resources in shale formations and other unconventional gas plays has also been the focus of drilling opportunities during 2011. Natural gas production growth in North America will likely be driven by our activity in three large unconventional plays: shale gas in British Columbia s Horn River basin, tight sands in British Columbia s Noel area, and the liquids-rich Granite Wash tight sands in the Anadarko basin of Oklahoma and the Texas Panhandle.

Kitimat LNG Project The time horizon and magnitude of Apache s shale gas development will be impacted by North American gas prices and investment decisions surrounding our ownership in the Kitimat LNG facility and a related proposed pipeline. The project has the potential to open new markets linked to oil prices in the Asia-Pacific region for gas from Apache s Canadian operations. In October 2011, Apache and its partners in the Kitimat LNG project announced that the National Energy Board granted the project a 20-year export license to ship LNG from Canada to international markets. This export approval represents a major milestone for Kitimat LNG and its partners. In addition, the Company progressed with the FEED study and continued efforts to secure firm sales commitments and required permits necessary to make a final investment decision on the LNG project.

Alaska Cook Inlet Acreage During 2011, Apache continued to accumulate acreage in Alaska s Cook Inlet and was the successful bidder on approximately 515,000 acres of onshore and offshore state leases. The Company has now accumulated approximately 800,000 gross acres in the Cook Inlet. We have current plans to conduct a seismic survey for the area and drill a well within the next 12 months.

Gulf of Mexico Deepwater Exploration Apache s strategic presence in the Gulf of Mexico deepwater portfolio was gained through the 2010 merger with Mariner Energy, Inc. At the end of 2011, the Company held approximately 750,000 gross acres across 148 blocks. The Bushwood, Wide Berth, and Mandy development projects are expected to begin production in the second quarter of 2012, with combined net initial production of 12 Mboe/d. In addition, the larger scale non-operated Lucius project was sanctioned in the fourth quarter of 2011. Apache has an 11.7-percent working interest in this development, with first production projected for 2014. We also plan to increase our exploration activity in 2012, having recently been awarded four deepwater exploration plans. We expect to drill or participate in drilling nine wells during 2012 compared with two wells drilled in the current year.

Significant Events

Egypt Political Unrest

In February 2011, former Egyptian president Hosni Mubarak stepped down, and the Egyptian Supreme Council of the Armed Forces took power. In November 2011, Egypt held its first round of parliamentary elections. Despite the Muslim Brotherhood s Freedom and Justice Party s victory in the parliamentary elections,

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Egypt remains under martial law. Although Egypt s first post-revolutionary parliament convened on January 23, 2012, the new Parliament remains subordinate to the Egyptian Supreme Council of the Armed Forces, which has stated its intention to turn over power to civilians following the presidential election expected in June 2012. Apache s operations, located in remote locations in the Western Desert, have continued uninterrupted, and we currently plan to invest $1 billion in Egypt in 2012.

Our operations in Egypt contributed 22 percent of our 2011 production and accounted for 10 percent of our year-end estimated proved reserves. At year-end 2011, 17 percent of our estimated discounted future net cash flows and 7.5 percent of our net capitalized oil and gas property was attributable to Egypt. For further information regarding our Egypt region, please see Note 13 Business Segment Information and Note 14 Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and other highly-rated international insurers covering its investments in Egypt. In the aggregate, these 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 $237.5 million sub-limit for currency inconvertibility. In addition, the Company has a separate policy with OPIC, which provides $225 million of coverage, including a self-insured retention of $37.5 million, 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 when actions taken by the government of Egypt prevent Apache from exporting our share of production.

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.

Potential Pipeline Capacity Constraints on North Sea Production

On April 8, 2011, BP Exploration Operating Company Limited (BP Exploration) sent a letter to Apache North Sea Limited alleging the potential for capacity constraints or increased tariffs relating to the Shippers Pipeline Liquids Transportation and Processing Agreement, dated January 11, 2003, between BP Exploration and Apache North Sea Limited. Apache North Sea Limited disagrees with the characterizations in the letter and will contest them vigorously. However, because this matter is unresolved, resolution of this matter, through litigation or otherwise, and/or forced renegotiation or modification of our existing contract with BP Exploration could, in the future, adversely affect our production and revenues from the Forties Field in the North Sea.

Argentina Tax and Royalty Claims

ENARGAS, an autonomous entity that functions under the Argentina Ministry of Economy, has issued administrative orders creating a tariff charge on all fuel gas used by oil and gas producers in field operations effective December 1, 2011. The tariff charge is applicable to the operations of Company affiliates in Argentina and could cost approximately $21 million annually. In addition, in late 2010 and early 2011, the Province of Tierra del Fuego notified Company affiliates of its claims for additional royalty on natural gas, crude oil, and liquefied petroleum gas. The Company s affiliates have initiated legal proceedings challenging both ENARGAS tariff charge and the Province s claims for additional royalty.

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Results of Operations

Oil and Gas Revenues

	For the Year Ended December 31, 2011		2010		2009	
	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution
Oil Revenues:						
United States	$ 4,163	33%	$ 2,683	30%	$ 1,922	32%
Canada	485	4%	388	4%	311	5%
North America	4,648	37%	3,071	34%	2,233	37%
Egypt	4,169	33%	2,875	32%	2,063	34%
Australia	1,552	12%	1,296	14%	230	4%
North Sea	2,072	16%	1,590	18%	1,356	22%
Argentina	238	2%	209	2%	207	3%
International	8,031	63%	5,970	66%	3,856	63%
Total (1)	$ 12,679	100%	$ 9,041	100%	$ 6,089	100%
Natural Gas Revenues:						
United States	$ 1,550	43%	$ 1,409	49%	$ 1,054	44%
Canada	1,033	29%	647	23%	546	23%
North America	2,583	72%	2,056	72%	1,600	67%
Egypt	621	17%	495	17%	490	21%
Australia	182	5%	163	6%	133	6%
North Sea	19	0%	16	0%	13	0%
Argentina	204	6%	132	5%	133	6%
International	1,026	28%	806	28%	769	33%
Total (2)	$ 3,609	100%	$ 2,862	100%	$ 2,369	100%
Natural Gas Liquids (NGL) Revenues:						
United States	$ 391	75%	$ 208	74%	$ 74	64%
Canada	99	19%	39	14%	20	17%
North America	490	94%	247	88%	94	81%
Egypt	1	0%	2	1%		0%
Argentina	31	6%	31	11%	22	19%
International	32	6%	33	12%	22	19%
Total	$ 522	100%	$ 280	100%	$ 116	100%
Total Oil and Gas Revenues:						

United States	$	6,104	36%	$	4,300	35%	$	3,050	36%
Canada		1,617	10%		1,074	9%		877	10%
North America		7,721	46%		5,374	44%		3,927	46%
Egypt		4,791	29%		3,372	28%		2,553	30%
Australia		1,734	10%		1,459	12%		363	4%
North Sea		2,091	12%		1,606	13%		1,369	16%
Argentina		473	3%		372	3%		362	4%
International		9,089	54%		6,809	56%		4,647	54%
Total	$	16,810	100%	$	12,183	100%	$	8,574	100%

(1) Financial derivative hedging activities and the North Sea fixed-price sales contract decreased 2011 and 2010 oil revenues by $379 million and $57 million, respectively, and increased 2009 oil revenues by $45 million.

(2) Financial derivative hedging activities increased natural gas revenues for 2011, 2010, and 2009 by $272 million, $222 million, and $136 million, respectively.

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Production

	For the Year Ended December 31,				
	2011	Increase (Decrease)	2010	Increase (Decrease)	2009
Oil Volume b/d:					
United States	119,415	+24%	96,576	+8%	89,133
Canada	14,252	-2%	14,581	-4%	15,186
North America	133,667	+20%	111,157	+7%	104,319
Egypt	103,912	+5%	99,122	+8%	92,139
Australia	38,228	-17%	45,908	+369%	9,779
North Sea	54,541	-4%	56,791	-7%	60,984
Argentina	9,597	-4%	9,956	-13%	11,505
International	206,278	-3%	211,777	+21%	174,407
Total (1)	339,945	+5%	322,934	+16%	278,726
Natural Gas Volume Mcf/d:					
United States	864,742	+18%	730,847	+10%	666,084
Canada	632,550	+60%	396,005	+10%	359,235
North America	1,497,292	+33%	1,126,852	+10%	1,025,319
Egypt	365,418	-3%	374,858	+3%	362,618
Australia	185,079	-7%	199,729	+9%	183,617
North Sea	2,284	-4%	2,391	-12%	2,703
Argentina	212,311	+15%	184,830	0%	184,557
International	765,092	+0%	761,808	+4%	733,495
Total (2)	2,262,384	+20%	1,888,660	+7%	1,758,814
NGL Volume b/d:					
United States	22,111	+60%	13,777	+125%	6,136
Canada	5,958	+107%	2,884	+38%	2,089
North America	28,069	+68%	16,661	+103%	8,225
Egypt	49	N/A	82	N/A	
North Sea	4	N/A		N/A	
Argentina	3,018	-5%	3,180	-2%	3,241
International	3,071	-6%	3,262	+1%	3,241
Total	31,140	+56%	19,923	+74%	11,466
BOE per day (3)					
United States	285,650	+23%	232,161	+13%	206,284
Canada	125,636	+51%	83,466	+8%	77,147

North America	411,286	+30%	315,627	+11%	283,431
Egypt	164,864	+2%	161,680	+6%	152,575
Australia	69,074	-13%	79,196	+96%	40,382
North Sea	54,925	-4%	57,190	-7%	61,435
Argentina	48,000	+9%	43,941	-3%	45,505
International	336,863	-2%	342,007	+14%	299,897
Total	748,149	+14%	657,634	+13%	583,328

(1) Approximately 29 percent of 2011 oil production was subject to financial derivative hedges, compared to 12 percent in 2010 and 10 percent in 2009.

(2) Approximately 16 percent of 2011 gas production was subject to financial derivative hedges, compared to 23 percent in 2010 and nine percent in 2009.

(3) The table shows production 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.

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Pricing

	For the Year Ended December 31,				
	2011	**Increase (Decrease)**	**2010**	**Increase (Decrease)**	**2009**
Average Oil Price Per barrel:					
United States	$ 95.51	+25%	$ 76.13	+29%	$ 59.06
Canada	93.19	+28%	72.83	+30%	56.16
North America	95.27	+26%	75.69	+29%	58.64
Egypt	109.92	+38%	79.45	+30%	61.34
Australia	111.22	+44%	77.32	+20%	64.42
North Sea	104.09	+36%	76.66	+26%	60.91
Argentina	68.02	+18%	57.47	+16%	49.42
International	106.67	+38%	77.21	+27%	60.58
Total (1)	102.19	+33%	76.69	+28%	59.85
Average Natural Gas Price Per Mcf:					
United States	$ 4.91	-7%	$ 5.28	+22%	$ 4.34
Canada	4.47	0%	4.48	+7%	4.17
North America	4.72	-6%	5.00	+17%	4.28
Egypt	4.66	+29%	3.62	-2%	3.70
Australia	2.69	+20%	2.24	+13%	1.99
North Sea	22.25	+19%	18.64	+42%	13.15
Argentina	2.64	+35%	1.96	0%	1.96
International	3.67	+27%	2.90	+1%	2.87
Total (2)	4.37	+5%	4.15	+12%	3.69
Average NGL Price Per barrel:					
United States	$ 48.42	+17%	$ 41.45	+26%	$ 33.02
Canada	45.72	+25%	36.61	+43%	25.54
North America	47.85	+18%	40.62	+31%	31.12
Egypt	66.36	N/A	69.75	N/A	
North Sea	65.45	N/A		N/A	
Argentina	27.90	+3%	27.08	+44%	18.76
International	28.56	+1%	28.15	+50%	18.76
Total	45.95	+19%	38.58	+40%	27.63

(1) Reflects per-barrel decrease of $3.05 and $0.48 in 2011 and 2010, respectively, and an increase of $0.44 in 2009 from financial derivative hedging activities and the North Sea fixed-price sales contract.

(2) Reflects per-Mcf increase of $0.33, $0.32, and $0.21 in 2011, 2010, and 2009, respectively, from financial derivative hedging activities.

Crude Oil Prices

A substantial portion of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of the Company s control. Prices we received for crude oil in 2011 were 33 percent above 2010, with political unrest and economic uncertainty increasing market volatility.

Continued volatility in the commodity price environment reinforces the importance of our balanced portfolio approach. International Dated Brent crudes and sweet crude from the Gulf Coast continue to be priced at a significant premium to WTI-based prices. We are realizing these premium prices on approximately 76 percent of our crude oil production. Crude oil prices realized in 2011 averaged $102.19 per barrel, compared with $76.69 per barrel in 2010. Our Egypt, Australia, and North Sea regions, which comprise 58 percent of our worldwide oil production and receive Dated Brent premiums, had 2011 oil realizations averaging $108.55 per barrel compared with 2010 oil realizations of $78.18 per barrel. Our Gulf Coast regions, which comprise 18 percent of our worldwide oil production and receive similar premiums, had price realizations averaging $108.26 per barrel, an increase of 37 percent over 2010 realizations of $79.00 per barrel.

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Crude oil tends to trade at a global price. With the exception of Argentina, price movements for all types and grades of crude oil generally move in the same direction. In Argentina, we currently sell our oil in the domestic market. The Argentine government imposes a sliding-scale tax on oil exports, which significantly influences prices domestic buyers are willing to pay. Domestic oil prices are currently indexed to a $42 per barrel base price, subject to quality adjustments and local premiums, and producers realize a gradual increase or decrease as market prices deviate from the base price. In Tierra del Fuego, similar pricing formulas exist; however, Apache retains the value-added tax collected from buyers, effectively increasing realized prices by 21 percent. As a result, 2011 oil prices realized from Tierra del Fuego oil production averaged $65.03 per barrel as compared to our Neuquén basin production, which averaged $53.68 per barrel.

Apache uses financial instruments to manage a portion of its exposure to fluctuations in crude oil prices, particularly in North America. In 2011, 29 percent of our oil production was subject to financial derivative hedges, reducing revenues by $379 million. In 2010, 12 percent of our oil production was subject to financial derivative hedges, reducing revenues by $57 million. For the year-end status of our derivatives, please see Note 3 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Natural Gas Prices

Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions. The majority of our gas sales contracts are indexed to prevailing local market prices, which again illustrates the importance of a geographically balanced portfolio.

Apache primarily sells natural gas into the North American market, where realized prices decreased six percent compared to 2010; however, approximately one-third of our natural gas is produced outside North America, where our average contracted prices rose 27 percent from 2010. Our primary markets include North America, Egypt, Australia, and Argentina. An overview of the market conditions in our primary gas-producing regions follows.

North America has a common market; most of our gas is sold on a monthly or daily basis at either monthly or daily market prices.

In Egypt, our gas is sold to EGPC, primarily under an industry pricing formula indexed to Dated Brent crude oil with a maximum gas price of $2.65 per MMBtu. Under a legacy oil-indexed contract, which expires at the end of 2012, there is no price cap for our gas up to 100 MMcf/d of gross production. Overall, the region averaged $4.66 per Mcf in 2011.

Australia has historically had a local market with a limited number of buyers and sellers resulting in mostly long-term, fixed-price contracts that are periodically adjusted for changes in the local consumer price index. 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 received on recent contracts are substantially higher than historical levels.

Argentina instituted the Gas Plus program 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 2011, the average Gas Plus volume sold by Apache was 55.1 MMcf/d at an average price of $4.89 per Mcf. In addition, Apache signed or extended Gas Plus contracts with industrial consumers totaling gross rates of 15.5 MMcf/d at $4.28 per Mcf through December 31, 2012.

Separate from the Gas Plus program, Apache sells volumes under Argentina s government-regulated pricing and into Argentina s unregulated market. The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. During 2011, we realized an average price of $1.06 per Mcf on government-regulated sales and an average price of $3.14 per Mcf on our unregulated market sales.

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Apache uses a variety of fixed-price contracts and derivatives to manage our exposure to fluctuations in natural gas prices, primarily in North America. In 2011, 16 percent of our gas production was subject to financial derivative hedges, increasing revenues by $272 million. In 2010, 23 percent of our gas production was subject to financial derivative hedges, increasing revenues by $222 million. For the year-end status of our derivatives, please see Note 3 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. For more specific information on marketing arrangements by country, please refer to Part I, Items 1 and 2 Business and Properties of this Form 10-K.

Crude Oil Revenues

2011 vs. 2010 During 2011, crude oil revenues totaled $12.7 billion, $3.7 billion higher than the 2010 total of $9.0 billion, driven by a 33-percent increase in average realized prices and a five-percent increase in worldwide production. Average daily production in 2011 was 339.9 Mb/d, with prices averaging $102.19 per barrel. Crude oil represented 75 percent of our 2011 oil and gas production revenues and 45 percent of our equivalent production, compared to 74 and 49 percent, respectively, in the prior year. Higher realized prices contributed $3.0 billion to the increase in full-year revenues, while higher production volumes added another $0.7 billion.

Worldwide oil production increased 17.0 Mb/d, driven by a 22.8 Mb/d increase in the US. The Permian region was up 11.6 Mb/d on properties added from the BP acquisitions, the Mariner merger and drilling and recompletion activity, offset by natural decline. The GOM onshore and offshore regions added 8.0 Mb/d as production from the Devon acquisition, the Mariner merger and drilling and recompletion activity was partially offset by natural decline. Central region production increased 3.2 Mb/d on drilling and recompletion activity. Egypt s gross oil production increased 15 percent from additional capacity at the Kalabsha oil processing facility, a successful drilling and recompletion program, and volumes acquired in the 2010 BP acquisition. Egypt s net production was up only five percent, as higher oil prices impact our cost recovery volumes. Australia production decreased 7.7 Mb/d as a result of repairs to the Van Gogh FPSO vessel, natural decline, and tropical cyclones in the first quarter of 2011.

2010 vs. 2009 During 2010, crude oil revenues totaled $9.0 billion, $2.9 billion higher than the 2009 total of $6.1 billion, driven by a 16-percent increase in worldwide production and a 28-percent increase in average realized prices. Average daily production in 2010 was 322.9 Mb/d, with prices averaging $76.69 per barrel. Crude oil represented 74 percent of our 2010 oil and gas production revenues and 49 percent of our equivalent production, compared to 71 percent and 48 percent, respectively, in the prior year. Higher realized prices contributed $1.7 billion to the increase in full-year revenues, while higher production volumes added another $1.2 billion.

Worldwide oil production increased 44.2 Mb/d, driven by a 36.1 Mb/d increase in Australia on new production from the Van Gogh and Pyrenees discoveries, which were brought online in the first quarter of 2010. U.S. production increased eight percent, or 7.4 Mb/d, with the Permian region up 4.4 Mb/d on properties added from the BP acquisitions, the Mariner merger, and drilling and recompletion activity. The Gulf Coast region added 1.8 Mb/d from properties acquired in the Devon acquisition, the Mariner merger, and drilling and recompletion activity. Central region production increased 1.2 Mb/d on drilling and recompletion activity. Gross production in Egypt increased 17 percent, while net production was up only eight percent, a function of the mechanics of our production-sharing contracts. Net production increased 7.0 Mb/d on production gains in the Shushan, Matruh and numerous other concessions. Additional capacity at the Kalabsha oil processing facility, as well as processing of condensate-rich gas through the Salam Gas Plant allowed by the new Jade manifold, allowed for much of the production gains. North Sea production decreased 4.2 Mb/d on natural decline and downtime.

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Natural Gas Revenues

2011 vs. 2010 Natural gas revenues for 2011 of $3.6 billion were $747 million higher than 2010 on a five-percent increase in realized prices and a 20-percent increase in production volumes. Realized prices in 2011 averaged $4.37 per Mcf, an increase of $0.22 per Mcf, which added $150 million to revenues. Worldwide production rose 374 MMcf/d, adding another $597 million to revenues.

Worldwide gas production rose 20 percent, driven by a 236.5 MMcf/d, or 60 percent, increase in Canada on additional volumes from properties acquired from BP and an active drilling and completion program. U.S. daily production was up 133.9 MMcf/d, or 18 percent, primarily a result of 2010 acquisition activity. GOM onshore and offshore regions production rose 73.4 MMcf/d on new drilling activity and properties acquired from Devon and the Mariner merger. Permian region production was up 56.4 MMcf/d on incremental volumes from properties added from the BP acquisition and Mariner merger and on increased drilling activity. Argentina s production was up 27 MMcf/d from drilling and recompletions. Daily gas production in Australia fell 14.7 MMcf/d on downtime from tropical cyclones and customer maintenance activities resulting in lower takes under our existing contractual arrangements. Egypt s gross production was up eight percent on a successful drilling program, additional gas throughput at the Obaiyed Gas Plant, and production from properties added in the BP acquisition. Net production was down three percent, as higher prices impacted our cost recovery volumes.

2010 vs. 2009 Natural gas revenues for 2010 of $2.9 billion were $493 million higher than 2009 on a 12-percent increase in realized prices and a seven-percent increase in production volumes. Realized prices in 2010 averaged $4.15 per Mcf, an increase of $0.46 per Mcf, which added $297 million to revenues. Worldwide production rose 130 MMcf/d, adding another $197 million to revenues.

Worldwide gas production rose in all of our core gas-producing regions. U.S. production was up 64.8 MMcf/d, or 10 percent. Driven by new drilling, recompletion activity, and properties acquired from Devon and the Mariner merger, Gulf Coast region production was up 38.2 MMcf/d. Permian region production was up 20.1 MMcf/d, primarily on volumes from properties acquired from BP. Central region production was up 6.5 MMcf/d as additional production from new drilling and recompletions outpaced natural decline. Canada region production increased 36.8 MMcf/d as the result of an active drilling and completion program at Horn River and additional volumes from properties acquired from BP. Production in Australia was up 16.1 MMcf/d on higher customer takes from our John Brookes field. In Egypt, gross production was up 14 percent, while net production rose only three percent, a function of our production-sharing contracts. The 12.2 MMcf/d increase in net production relative to 2009 was attributable to several factors, including a successful drilling and recompletion program on our Matruh concession, additional volumes processed through the Obaiyed Gas Plant and a full year of additional capacity provided by the completion of two new gas trains at the Salam Gas Plant. Argentina s production was up marginally as production from new drilling and recompletions was mostly offset by natural decline.

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Operating Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and an equivalent unit of production (boe) basis. Our discussion may reference expenses on a boe basis, on an absolute dollar basis or both, depending on context.

	Year Ended December 31,			Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
		(In millions)			(Per boe)	
Depreciation, depletion and amortization:						
Oil and gas property and equipment						
Recurring	$ 3,814	$ 2,861	$ 2,202	$ 13.97	$ 11.92	$ 10.34
Additional	109		2,818	.40		13.24
Other assets	281	222	193	1.03	.92	.91
Asset retirement obligation accretion	154	111	105	.56	.46	.49
Lease operating expenses	2,605	2,032	1,662	9.54	8.47	7.81
Gathering and transportation	296	178	143	1.08	.73	.67
Taxes other than income	899	690	580	3.29	2.88	2.72
General and administrative expenses	459	380	344	1.68	1.58	1.62
Merger, acquisitions & transition	20	183		.07	.77	
Financing costs, net	158	229	242	.58	.95	1.13
Total	$ 8,795	$ 6,886	$ 8,289	$ 32.20	$ 28.68	$ 38.93

Depreciation, Depletion and Amortization

The following table details the changes in recurring depreciation, depletion and amortization (DD&A) of oil and gas properties between December 31, 2011 and December 31, 2009:

	Recurring DD&A (In millions)
2009	$ 2,202
Volume change	317
Rate change	342
2010	$ 2,861
Volume change	349
Rate change	604
2011	$ 3,814

2011 vs. 2010 Recurring full-cost depletion expense increased $953 million on an absolute dollar basis: $604 million on higher rate and $349 million from additional production. Our full-cost depletion rate increased $2.05 to $13.97 per boe as costs to acquire, find, and develop reserves, which were significantly impacted by higher oil prices, exceeded our historical cost basis. In 2011, additional depletion expense of $60 million was

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associated with the write-off of the carrying value of our Chilean oil and gas property leases relinquished during 2011, and $49 million was associated with impairments of new venture seismic activity in countries where Apache is pursuing exploration opportunities but has not yet established a presence. Other asset depreciation increased $59 million over 2010 primarily on higher other asset balances from 2010 acquisitions.

2010 vs. 2009 Recurring full-cost depletion expense increased $659 million on an absolute dollar basis: $342 million on higher rate and $317 million from additional production. Our full-cost depletion rate increased $1.58 to $11.92 per boe as costs to acquire, find, and develop reserves exceeded our historical cost basis. In 2009, additional depletion expense of approximately $2.8 billion was associated with a non-cash write-down of the carrying value of our March 31, 2009, proved oil and gas property balances in the U.S. and Canada.

Lease Operating Expenses

Lease operating expenses (LOE) include several components: direct operating costs, repair and maintenance, and workover costs.

Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as labor, boats, helicopters, materials, and supplies. Oil, which contributed nearly half of our production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties, which account for all of our production in Australia and the North Sea and 86 percent of our production from the U.S. Gulf Coast regions, and in areas with remote plants and facilities. Workovers accelerate production; hence, activity generally increases with higher commodity prices. Foreign exchange rate fluctuations generally impact the Company s LOE, with a weakening U.S. dollar adding to per-unit costs and a strengthening U.S. dollar lowering per-unit costs in our international regions.

The following table details the LOE rate impact by component:

For the Year Ended December 31, 2011		For the Year Ended December 31, 2010	
	Per boe		Per boe
2010 LOE	$ 8.47	2009 LOE	$ 7.81
Acquisitions, net of associated production	(0.02)	Acquisitions, net of associated production	0.27
FX impact	0.23	FX impact	0.22
Labor and pumper costs	0.21	Equipment rental	0.22
Workover costs	0.18	Workover costs	0.16
Chemicals, power, and fuel	0.13	Stock-based compensation	0.14
Transportation	0.11	Labor and pumper costs	0.08
Other	0.12	Material	0.07
Other decreased production	0.11	Chemicals, power, and fuel	0.07
2011 LOE	$ 9.54	Other	0.20
		Other increased production	(0.77)
		2010 LOE	$ 8.47

2011 vs. 2010 Our 2011 LOE increased $573 million from 2010, or 28 percent. On a per-unit basis, LOE increased 13 percent due to higher costs on the items listed above.

2010 vs. 2009 Our 2010 LOE increased $370 million from 2009, or 22 percent. On a per-unit basis, LOE increased eight percent with a 22 percent increase on higher costs, offset by a 14 percent decline related to increased production. The rate was impacted by the items listed above.

Gathering and Transportation

We generally sell oil and natural gas under two common types of agreements, both of which include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a lower relative price to reflect transportation costs to be incurred by the purchaser. In this case, we record sales at the netback price received from the purchaser. Alternatively, we sell oil or natural gas at a specific delivery point, pay our own transportation to a third-party carrier, and receive a price with no transportation deduction. In this case, we record the separate transportation cost as gathering and transportation costs.

In the U.S., Canada, and Argentina, we sell oil and natural gas under both types of arrangements. In the North Sea, we pay transportation charges to a third-party carrier. In Australia, oil and natural gas are sold under netback arrangements. In Egypt, our oil and natural gas production is primarily sold to EGPC under netback arrangements; however, we also export crude oil under both types of arrangements.

The following table presents gathering and transportation costs we paid directly to third-party carriers for each of the periods presented:

	For the Year Ended December 31,		
	2011	2010	2009
		(In millions)	
U.S.	$ 64	$ 42	$ 36
Canada	166	75	53
North Sea	25	25	26
Egypt	34	31	23
Argentina	7	5	5
Total Gathering and Transportation	$ 296	$ 178	$ 143

2011 vs. 2010 Gathering and transportation costs increased $118 million from 2010. Canada s expense increased $91 million from a combination of an increase in gas volumes, higher average rates, and foreign exchange impacts. Average per-unit costs were directly influenced by Apache s increased production in Canada s Horn River basin and properties acquired during 2010, where the associated gathering, processing, and transportation contracts have higher average rates than Apache s legacy properties. The $22 million increase in the U.S. is directly related to increased volumes.

2010 vs. 2009 Gathering and transportation costs increased $35 million from 2009. The increase in the U.S. resulted from an increase in both the volumes transported under arrangements where we pay costs directly to third parties and in rates. The increase in Canada resulted from an increase in volumes, rate, and foreign exchange rates. North Sea costs were down on lower production and foreign exchange rates. Egypt costs increased as a result of higher shipping, handling, and pipeline fees as compared to the prior year.

Taxes Other Than Income

Taxes other than income primarily consist of U.K. Petroleum Revenue Tax (PRT), severance taxes on properties onshore and in state or provincial waters off the coast of the U.S., Australia, and Argentina, and ad valorem taxes on properties in the U.S. and Canada. Severance taxes are generally based on a percentage of oil and gas production revenues, while the U.K. PRT is assessed on net receipts (revenues less qualifying operating costs and capital spending) from the Forties and Nelson fields in the U.K. North Sea. We are subject to a variety of other taxes including U.S. franchise taxes, Australian Petroleum Resources Rent tax, and various Canadian taxes, including the Freehold Mineral tax, Saskatchewan Capital tax, and Saskatchewan Resources surtax. We also pay taxes on invoices and bank transactions in Argentina. The table below presents a comparison of these expenses:

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions)		
U.K. PRT	$ 538	$ 422	$ 383
Severance taxes	212	142	88
Ad valorem taxes	94	80	55
Other taxes	55	46	54
Total Taxes other than income	$ 899	$ 690	$ 580

2011 vs. 2010 Taxes other than income were $209 million higher than 2010. U.K. PRT increased $116 million over the comparable 2010 period as a result of a 27-percent increase in net receipts, primarily driven by higher revenues. Prior-year property acquisitions and higher realized oil and gas prices resulted in a $70 million and $14 million increase to severance and ad valorem tax expense, respectively.

2010 vs. 2009 Taxes other than income were $110 million higher than 2009. U.K. PRT increased $39 million over 2009 as a result of a 10-percent increase in net receipts, primarily driven by higher revenues. Severance taxes increased $54 million from higher taxable revenues in the U.S., predominantly resulting from acquisitions, and consistent with higher realized oil and natural gas prices relative to the prior year. The $25 million increase in ad valorem taxes resulted from higher taxable valuations in the U.S. associated with increases in oil and natural gas prices relative to the prior year and the BP and Devon acquisitions and the Mariner merger.

General and Administrative Expenses

2011 vs. 2010 General and administrative (G&A) expenses increased $79 million, or 21 percent from 2010. On a per-unit basis, G&A expenses increased six percent, or $.11 per boe: $.07 per boe on higher insurance costs and $.04 per boe on nonrecurring expenses.

2010 vs. 2009 G&A expenses were $36 million higher in 2010 than in 2009. On a per boe basis, G&A expenses decreased two percent as the effect of higher volumes more than offset the increase in costs.

Merger, Acquisitions & Transition Costs

In 2011, the Company recognized $20 million in merger, acquisitions, & transition costs, reflecting additional expenses related to our 2010 BP asset acquisitions and the Mariner merger as well as costs arising from our 2011 acquisition of Mobil North Sea Limited.

In 2010, the Company recognized $183 million in merger, acquisitions, & transition costs related to our BP and Devon acquisitions and the Mariner merger. A summary of these costs follows:

	For the Year Ended December 31,	
	2011	2010
	(In millions)	
Separation and retention costs	$ 12	$ 114
Investment banking fees		42
Other costs	8	27
Total Merger, Acquisitions & Transition	$ 20	$ 183

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Financing Costs, Net

Net financing costs incurred during the periods noted are composed of the following:

	For the Year Ended December 31,		
	2011	2010	2009
		(In millions)	
Interest expense	$ 433	$ 345	$ 309
Amortization of deferred loan costs	5	17	6
Capitalized interest	(263)	(120)	(61)
Interest income	(17)	(13)	(12)
Total Financing costs, net	$ 158	$ 229	$ 242

2011 vs. 2010 Net financing costs decreased $71 million from 2010. The decrease is primarily related to a $143 million increase in capitalized interest, the result of additional unproved balances from the BP acquisitions and Mariner merger. This decrease is partially offset by an $88 million increase in interest expense from debt issuances in 2010.

2010 vs. 2009 Net financing costs decreased $13 million from 2009. The decrease is primarily related to a $59 million increase in capitalized interest, the result of additional unproved balances from the BP acquisitions and Mariner merger. This decrease is partially offset by a $36 million increase in interest expense from debt issuances in 2010 and $11 million higher amortization of deferred loan costs related to the new debt and repayment of the Australian project financing facility.

Provision for Income Taxes

2011 vs. 2010 The provision for income taxes totaled $3.5 billion in 2011 compared to $2.2 billion in 2010, driven by a 55 percent increase in income before income taxes and an increase in the effective tax rate to 43.4 percent in 2011 from 41.8 percent in 2010. The largest driver of the increased tax rate was an increase in the U.K. corporate income tax rate on North Sea oil and gas profits from 50 percent to 62 percent. As a result of the enacted legislation, in 2011 the Company recorded a tax charge of $218 million resulting from the remeasurement of our U.K. deferred tax liability as of December 31, 2010. The effective rates for 2011 and 2010 were also impacted by the effect of currency exchange rates on our foreign deferred tax liabilities.

2010 vs. 2009 The provision for income taxes totaled $2.2 billion in 2010 compared to $611 million in 2009. The effective rates for 2010 and 2009 were impacted by the effect of currency exchange rates on our foreign deferred tax liabilities and other net tax settlements. Total taxes and the effective rate for 2009 were also impacted by the magnitude of the taxes related to the full-cost write-down in that year.

Significant Acquisitions and Divestitures

2011 Activity

On December 30, 2011, Apache completed the acquisition of Exxon Mobil Corporation s U.K. subsidiary, Mobil North Sea Limited. The assets acquired include: operated interests in the Beryl, Nevis, Nevis South, Skene, and Buckland fields; operated interest in the Beryl/Brae gas pipeline and the SAGE gas plant; non-operated interests in the Maclure, Scott, and Telford fields; and Benbecula (west of Shetlands) exploration acreage. This acquisition was funded with $1.25 billion of existing cash on hand.

In February and March 2011, Apache completed two separate transactions to align ownership and interests on the planned Kitimat LNG facility and pipeline development. Apache Canada currently owns a 40-percent interest in both the Kitimat facility and the pipeline.

2010 Activity

In the fourth quarter of 2010, Apache acquired Mariner, an independent exploration and production company, in a stock and cash transaction totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt in connection with the merger. The transaction was accounted for as a business combination, with Mariner s assets and liabilities reflected in Apache s financial statements at fair value. Mariner s oil and gas properties are primarily located in the Gulf of Mexico deepwater and shelf, the Permian Basin, and onshore in the Gulf Coast. The Permian Basin and Gulf of Mexico shelf assets are complementary to Apache s existing holdings and provide an inventory of future potential drilling locations, particularly in the Spraberry and Wolfcamp formation oil plays of the Permian Basin. Additionally, Mariner has accumulated acreage in emerging unconventional shale oil resources in the U.S.

In the third and fourth quarters of 2010, Apache completed the acquisition of BP s oil and gas operations, related infrastructure, and acreage in the Permian Basin of west Texas and New Mexico, substantially all of BP s Western Canadian upstream natural gas assets, and BP s interests in four development licenses and one exploration concession (East Badr El Din) in the Western Desert of Egypt. The aggregate purchase price of the BP acquisitions, subsequent to exercise of preferential purchase rights, was $6.4 billion, subject to normal post-closing adjustments. The effective date of these acquisitions was July 1, 2010.

In the second quarter of 2010, Apache completed an acquisition of oil and gas assets on the Gulf of Mexico shelf from Devon for $1.05 billion, subject to normal post-closing adjustments. The acquisition from Devon was effective January 1, 2010, and included 477,000 acres across 150 blocks.

During the first quarter of 2010, Apache Canada, through its subsidiaries, closed the acquisition of a 51-percent interest in the Kitimat LNG facility and a 25.5-percent interest in a partnership that owns a related proposed pipeline.

Subsequent Events

The following significant transactions occurred subsequent to December 31, 2011:

In January 2012, Apache agreed to acquire Cordillera Energy Partners III LLC, a privately held company with approximately 254,000 net acres in the Granite Wash, Tonkawa, Cleveland, and Marmaton plays in western Oklahoma and the Texas Panhandle. Upon closing, the sellers will receive approximately 6.3 million shares of Apache common stock and $2.2 billion in cash, to be funded with cash on hand and debt. The effective date of the transaction is September 1, 2011, with closing projected to be in the second quarter of 2012, subject to customary closing conditions.

On January 31, 2012, a subsidiary of Apache Energy Limited acquired a 49-percent interest in Burrup Holdings Limited (BHL) for $439 million, including working capital adjustments. The transaction was funded with debt. BHL is the owner of an ammonia fertilizer plant on the Burrup Peninsula of Western Australia. Apache has been supplying natural gas to the plant since operations commenced in 2006. Yara Australia Pty Ltd (Yara) owns the remaining 51 percent of BHL and will operate the plant, which has been rebranded Yara Pilbara. Apache also acquired an interest in a planned technical ammonia nitrate plant to be developed with Yara.

For further information regarding these acquisitions, please see Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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Capital Resources and Liquidity

Operating cash flows are a primary source of liquidity. Apache s cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Significant deterioration in commodity prices negatively impacts revenues, earnings and cash flows, capital spending, and potentially our liquidity if spending does not trend downward as well. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactive as commodity prices in the short-term.

Apache s long-term operating cash flows are dependent on reserve replacement and the level of costs required for ongoing operations. Our business, as with other extractive industries, is a depleting one in which each barrel produced must be replaced or the Company and its reserves, a critical source of future liquidity, will shrink. Cash investments are required continuously to fund exploration and development projects and acquisitions, which are necessary to offset the inherent declines in production and proven reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of our exploration and development activities or our ability to acquire additional reserves at reasonable costs. For a discussion of risk factors related to our business and operations, please see Part I, Item 1A Risk Factors of this Form 10-K.

We may also elect to utilize available committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the occasional sale of nonstrategic assets for all other liquidity and capital resource needs.

We believe the liquidity and capital resource alternatives available to Apache, combined with internally-generated cash flows, will be adequate to fund short-term and long-term operations, including our capital spending program, repayment of debt maturities, and any amount that may ultimately be paid in connection with contingencies.

Apache s primary uses of cash are exploration, development, and acquisition of oil and gas properties, costs necessary to maintain ongoing operations, repayment of principal and interest on outstanding debt, and payment of dividends. We fund our exploration and development activities primarily through operating cash flows and budget capital expenditures based on projected cash flows.

For additional information, please see Part I, Items 1 and 2 Business and Properties and Part I, Item 1A Risk Factors of this Form 10-K.

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Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the years presented:

	Year Ended December 31, 2011	2010 (In millions)	2009
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 9,953	$ 6,726	$ 4,224
Commercial paper and bank loan borrowings, net		318	
Sale of short-term investments			792
Sale of oil and gas properties	422		3
Project financing draw-downs			250
Fixed-rate debt borrowings		2,470	
Proceeds from issuance of common stock		2,258	
Proceeds from issuance of depositary shares		1,227	
Common stock activity	52	70	28
Other	32	36	35
	10,459	13,105	5,332
Uses of Cash and Cash Equivalents:			
Capital expenditures [(1)]	7,078	4,922	3,632
Acquisitions	1,813	8,360	310
Commercial paper, credit facility and bank loan repayments, net	925		2
Project financing repayment		350	
Payments on fixed-rate notes		1,023	100
Redemption of preferred stock			98
Dividends	306	226	209
Other	176	138	114
	10,298	15,019	4,465
Increase (decrease) in cash and cash equivalents	$ 161	$ (1,914)	$ 867

(1) The table presents capital expenditures on a cash basis; therefore, the amounts differ from those discussed elsewhere in this document, which include accruals.

Net Cash Provided by Operating Activities

Cash flows are our primary source of capital and liquidity and are impacted, both in the short-term and the long-term, by volatile oil and natural gas prices. The factors in determining operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation (ARO) accretion, and deferred income tax expense, which affect earnings but do not affect cash flows.

Net cash provided by operating activities for 2011 totaled $10.0 billion, up $3.3 billion from 2010. The increase reflects the $4.6 billion impact of higher oil and gas revenues, with higher commodity prices contributing $3.2 billion, and a 14-percent increase in daily equivalent production adding another $1.4 billion. This increase was partially offset by higher income tax payments in 2011 as compared to the 2010 period.

For a detailed discussion of commodity prices, production, and expenses, please see Results of Operations in this Item 7. For additional detail on the changes in operating assets and liabilities and the non-cash expenses which do not impact net cash provided by operating activities, please see the Statement of Consolidated Cash Flows in the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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Sale of Oil and Gas Properties

During 2011, Apache completed the sale of certain properties in Canada and the U.S. for $422 million. Divestitures comprised several non-strategic assets.

Proceeds from Debt, Common Stock and Share Issuance

On July 28, 2010, in conjunction with Apache s $6.4 billion acquisition of properties from BP, the Company issued 26.45 million shares of common stock and 25.3 million depositary shares. Proceeds, after underwriting discounts and before expenses, from the common stock and depositary share offerings totaled approximately $2.3 billion and $1.2 billion, respectively.

On August 20, 2010, the Company issued $1.5 billion principal amount of senior unsecured 5.1-percent notes maturing September 1, 2040. The proceeds were used to repay borrowings under a bridge facility and the Company s commercial paper program that were used to finance the 2010 BP acquisitions. On December 3, 2010, the Company issued $500 million principal amount of senior unsecured 3.625-percent notes maturing February 1, 2021, and $500 million principal amount of senior unsecured 5.25-percent notes maturing February 1, 2042. The proceeds were used to redeem the outstanding public debt of $1.0 billion assumed upon completion of Apache s acquisition of Mariner in November 2010.

Repayment of Commercial Paper and Lines of Credit

During 2011, Apache repaid $925 million on commercial paper and money market lines of credit. For further discussion of our commercial paper program, please see Liquidity in this Item 7 and Note 6 Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Dividends

The Company has paid cash dividends on its common stock for 47 consecutive years through 2011. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other relevant factors. Common stock dividends paid during 2011 totaled $230 million, compared with $206 million in 2010 and $202 million in 2009. The 2011 and 2010 periods included dividend payments of $76 million and $20 million, respectively, on the Company s Series D Preferred Stock. The 2009 period included dividend payments of $7 million on the Company s Series B Preferred Stock.

Capital Expenditures

We fund exploration and development activities primarily through operating cash flows and budget capital expenditures based on projected operating cash flows. Our operating cash flows, both in the short and long term, are impacted by highly volatile oil and natural gas prices, production levels, industry trends impacting operating expenses, and our ability to continue to acquire or find high-margin reserves at competitive prices. For these reasons, operating cash flow forecasts are revised monthly in response to changing market conditions and production projections. Apache routinely adjusts capital expenditure budgets in response to these adjusted operating cash flow forecasts and market trends in drilling and acquisitions costs.

Historically, we have used a combination of operating cash flows, borrowings under lines of credit and commercial paper program and, from time to time, issues of public debt or common stock to fund significant acquisitions.

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The following table details capital expenditures for each country in which we do business.

	Year Ended December 31, 2011	2010	2009
	(In millions)		
Exploration and Development (E&D):			
United States	$ 2,768	$ 1,623	$ 929
Canada	817	860	412
North America	3,585	2,483	1,341
Egypt	896	757	676
Australia	576	624	602
North Sea	823	617	375
Argentina	346	240	140
Other International	61	20	11
International	2,702	2,258	1,804
Worldwide Exploration and Development Costs	6,287	4,741	3,145
Gathering, Transmission and Processing Facilities (GTP):			
United States	27		
Canada	148	159	83
Egypt	111	182	151
Australia	345	162	69
Argentina	12	3	2
Total GTP Costs	643	506	305
Asset Retirement Costs	819	459	288
Capitalized Interest	263	120	61
Capital Expenditures, excluding Acquisitions	8,012	5,826	3,799
Acquisitions, including GTP	3,189	11,557	310
Asset Retirement Costs Acquired	592	847	5
Total Capital Expenditures	$ 11,793	$ 18,230	$ 4,114

Exploration and Development Apache continues to focus on spending within the limits of our operating cash flows. As a result of Apache s acquisitions in 2010 and the rise in commodity prices, our 2011 drilling and development budgets were increased while remaining below projected increases in operating cash flows in order to pay down debt. Accordingly, worldwide E&D expenditures for 2011 were 33 percent higher than 2010.

E&D spending in North America, which totaled 57 percent of worldwide E&D spending, was up 44 percent in 2011 from the prior year on increased activity in every U.S. region. U.S. E&D expenditures were $1.1 billion, or 71 percent, higher than year-ago levels primarily on activity in the Permian region, where we continue an aggressive drilling program on our Mariner-acquired Deadwood acreage. Current-year activity also includes expenditures on Mariner-acquired deepwater properties for ongoing field development activities at Mandy, Wideberth, and Lucius. Our Central region s active horizontal drilling program in the Granite Wash and Cherokee plays further contributed to our increase in expenditures.

E&D expenditures outside of North America increased 20 percent over 2010 to $2.7 billion. E&D spending in the North Sea was up $206 million from prior-year levels on the Forties field drilling program and the

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construction of the Forties Alpha satellite platform. Egypt was $139 million higher than the prior year on continued drilling activity across all major basins. Argentina expenditures were up $106 million on additional drilling and development activity.

Gathering, Transmission and Processing Facilities We invested $643 million in GTP in 2011 compared to $506 million in 2010. GTP expenditures in Australia consisted of construction activity at the Devil Creek and Macedon gas plants. Australia has also incurred costs related to the FEED study and purchases of long-lead items for the Wheatstone LNG project. Activity in Canada was centered on the Kitimat LNG development and in the Horn River basin, with expenditures for compressor stations, a water treatment facility, gathering systems, and a gas processing plant. Expenditures in Egypt primarily comprised final stages of construction on the Kalabsha oil processing facility. In addition, approximately $338 million of the value of our 2011 acquisitions is associated with GTP.

Asset Retirement Costs In 2011, we recorded $819 million of additional future asset retirement costs associated with our worldwide drilling programs and upward revisions to prior-year estimates for timing and costs.

Acquisitions We acquired $3.2 billion of oil and gas properties in 2011 compared to $11.6 billion in 2010. We also assumed $592 million in asset retirement costs. Acquisition capital expenditures occur as attractive opportunities arise and, therefore, vary from year to year. For information regarding our acquisitions and divestitures, please see Significant Acquisitions and Divestitures in this Item 7 and Note 2 Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Liquidity

	At December 31,	
(In millions, except percentages)	**2011**	**2010**
Cash and cash equivalents	$ 295	$ 134
Total debt	7,216	8,141
Shareholders equity	28,993	24,377
Available committed borrowing capacity	3,300	2,387
Floating-rate debt/total debt	0.4%	12%
Percent of total debt to capitalization	20%	25%

Cash and Cash Equivalents

We had $295 million in cash and cash equivalents at December 31, 2011, of which $237 million of cash was held by foreign subsidiaries, and approximately $58 million was held by Apache Corporation and U.S. subsidiaries. The cash held by foreign subsidiaries is subject to additional U.S. income taxes if repatriated. Almost all of the cash is denominated in U.S. dollars and, at times, is invested in highly liquid, investment-grade securities with maturities of three months or less at the time of purchase. We intend to use cash from our international subsidiaries to fund international projects.

Debt

At December 31, 2011, outstanding debt, which consisted of notes, debentures, commercial paper, and uncommitted bank lines, totaled $7.2 billion. Current debt consists of $400 million in 6.25-percent debentures due in April 2012 and $31 million borrowed under uncommitted money market/overdraft lines of credit in Argentina. We have $900 million of debt maturing in 2013, $350 million maturing in 2015, and the remaining $5.6 billion maturing intermittently in years 2016 through 2096.

The Company s debt-to-capitalization ratio as of December 31, 2011 was 20 percent as compared to 25 percent at December 31, 2010.

Available Credit Facilities

As of December 31, 2011, the Company had unsecured committed revolving syndicated bank credit facilities totaling $3.3 billion, of which $2.3 billion matures in May 2013 and $1.0 billion matures in August 2016. The facilities consist of a $1.5 billion facility, a $1.0 billion facility and a $450 million facility in the U.S., a $200 million facility in Australia, and a $150 million facility in Canada. As of December 31, 2011, available borrowing capacity under the Company s credit facilities was $3.3 billion. The U.S. credit facilities are used to support Apache s commercial paper program.

The financial covenants of the credit facilities require the Company to maintain a debt-to-capitalization ratio of not greater than 60 percent at the end of any fiscal quarter. The negative covenants include restrictions on the Company s ability to create liens and security interests on our assets, with exceptions for liens typically arising in the oil and gas industry, purchase money liens, and liens arising as a matter of law, such as tax and mechanics liens. The Company may incur liens on assets located in the U.S. and Canada of up to five percent of the Company s consolidated assets, or approximately $2.6 billion as of December 31, 2011. There are no restrictions on incurring liens in countries other than U.S. and Canada. There are also restrictions on Apache s ability to merge with another entity, unless the Company is the surviving entity, and a restriction on our ability to guarantee debt of entities not within our consolidated group.

There are no clauses in the facilities that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes. The credit facility agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, the agreements allow the lenders to accelerate payments and terminate lending commitments if Apache, or any of its U.S. or Canadian subsidiaries, defaults on any direct payment obligation in excess of $100 million or has any unpaid, non-appealable judgment against it in excess of $100 million. The Company was in compliance with the terms of the credit facilities as of December 31, 2011.

At the Company s option, the interest rate for the facilities is based on a base rate, as defined, or LIBOR plus a margin determined by the Company s senior long-term debt rating.

At December 31, 2011, the margin over LIBOR for committed loans was 0.19 percent on the $1.5 billion facility, 0.875 percent on the $1.0 billion facility, and 0.23 percent on the $450 million facility in the U.S., the $200 million facility in Australia, and the $150 million facility in Canada. If the total amount of the loans borrowed under the $1.5 billion facility equals or exceeds 50 percent of the total facility commitments, then an additional 0.05 percent will be added to the margins over LIBOR. If the total amount of the loans borrowed under the $450 million facility in the U.S., the $200 million facility in Australia, and the $150 million facility in Canada equals or exceeds 50 percent of the total facility commitments, then an additional 0.10 percent will be added to the margins over LIBOR. The Company also pays quarterly facility fees of 0.06 percent on the total amount of the $1.5 billion facility, 0.125 percent on the total amount of the $1.0 billion facility, and 0.07 percent on the total amount of the other three facilities. The facility fees vary based upon the Company s senior long-term debt rating.

Substantially all of the banks with lending commitments to the Company have credit ratings of at least single-A, which in some cases is based on government support. There is no assurance that the financial condition of these banks will not deteriorate. We closely monitor the ratings of the 28 banks in our bank group. Having a large bank group allows the Company to mitigate the potential impact of any bank s failure to honor its lending commitment.

Commercial Paper Program

The Company has available a $2.95 billion commercial paper program, which generally enables Apache to borrow funds for up to 270 days at competitive interest rates. Our 2011 weighted-average interest rate for commercial paper was 0.37 percent. If the Company is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, the Company s U.S. credit facilities are available as a 100-percent backstop. The commercial paper program is fully supported by available borrowing capacity under U.S. committed credit facilities, which expire in 2013 and 2016. As of December 31, 2011, the Company had no commercial paper outstanding.

Future Debt and Stock Issuances

Subsequent to year-end, Apache plans to issue additional equity and debt in conjunction with the recently announced Cordillera Energy acquisition. As discussed above in Significant Acquisitions and Divestures in this Item 7, the Company is planning to issue approximately 6.3 million shares of common stock to the sellers and fund the remaining $2.2 billion balance with cash on hand and debt at closing, which is projected to be in the second quarter of 2012.

Dividend Increase

Based on strong future growth prospects and Apache s financial position, the Board of Directors approved a 13-percent increase to $0.17 per share for the regular quarterly cash dividend on the Company s common shares. This increase applies to the dividend on common shares payable on May 22, 2012, to stockholders of record on April 23, 2012.

Off-Balance Sheet Arrangements

Apache enters into customary agreements in the oil and gas industry for drilling rig commitments, firm transportation agreements, and other obligations as described below in Contractual Obligations in this Item 7. Other than the off-balance sheet arrangements described herein, Apache does not have any off-balance sheet arrangements with unconsolidated entities that are reasonably likely to materially affect our liquidity or capital resource positions.

Contractual Obligations

The following table summarizes the Company s contractual obligations as of December 31, 2011. For additional information regarding these obligations, please see Note 6 Debt 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.

Contractual Obligations[a]	Note Reference	Total	2012	2013-2014	2015-2016	2017 & Beyond
			(In millions)			
Debt, at face value	Note 6	$ 7,262	$ 431	$ 900	$ 351	$ 5,580
Interest payments	Note 6	7,358	399	708	660	5,591
Drilling rig commitments[b]	Note 8	799	288	510	1	
Purchase obligations[c]	Note 8	1,408	578	603	186	41
Firm transportation agreements	Note 8	756	117	224	149	266
Office and related equipment	Note 8	281	52	79	54	96
Other operating lease obligations[d]	Note 8	694	184	227	183	100
Total Contractual Obligations		$ 18,558	$ 2,049	$ 3,251	$ 1,584	$ 11,674

(a) This table does not include the Company s liability for dismantlement, abandonment, and restoration costs of oil and gas properties, derivative liabilities, pension or postretirement benefit obligations, or tax reserves. For additional information regarding these liabilities, please see Notes 5, 3, 8, and 7, respectively, in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(b) This represents minimum future expenditures for drilling rig services. Apache s expenditures for drilling rig services will exceed such minimum amounts to the extent Apache utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract.

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(c) Purchase obligations represent agreements to purchase goods or services that are enforceable, are legally binding, and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the appropriate timing of the transaction. These include minimum commitments associated with take-or-pay contracts, hydraulic fracturing service agreements, obtaining and processing seismic data, and contractual obligations to buy or build oil and gas plants and facilities.

(d) Other operating lease obligations pertain to other long-term exploration, development, and production activities. The Company has work-related commitments for oil and gas operations equipment, acreage maintenance commitments, FPSOs, and aircraft, among other things.

Apache is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. Apache s management feels that it has adequately reserved for its contingent obligations, including approximately $120 million for environmental remediation and approximately $20 million for various contingent legal liabilities. For a detailed discussion of the Company s environmental and legal contingencies, please see Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

The Company also had approximately $118 million accrued as of December 31, 2011, for an insurance contingency as a member of Oil Insurance Limited (OIL). This insurance co-op insures specific property, pollution liability, and other catastrophic risks of the Company. As part of its membership, the Company is contractually committed to pay a withdrawal premium if we elect to withdraw from OIL. Apache does not anticipate withdrawal from the insurance pool; however, the potential withdrawal premium is calculated annually based on past losses and the nature of our asset base.

Insurance Program

We maintain insurance coverage that includes coverage for physical damage to our assets, third party liability, workers compensation, employers liability, sudden pollution, and other risks. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

Our current insurance policies covering physical damage to our assets provide $1 billion in coverage per occurrence. These policies also provide sudden pollution coverage. Coverage for damage to our U.S. Gulf of Mexico assets specifically resulting from a named windstorm, however, is subject to a maximum of $250 million per named windstorm, which includes a self-insured retention of 40 percent of the losses above a $100 million deductible, and is limited to a maximum of two storms per year.

Our current insurance policies covering general liabilities provide coverage of $610 million per occurrence subject to Apache s interest. This coverage is in excess of existing policies, including, but not limited to, charterer s liability, aircraft liability, employer s liability, and automobile liability. Our service agreements, including drilling contracts, generally indemnify Apache for injuries and death of the service provider s employees as well as subcontractors hired by the service provider.

Our insurance policies generally renew in January and June of each year. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable.

Apache purchases multi-year political risk insurance from the OPIC and other highly rated international insurers covering its investments in Egypt. In the aggregate, these 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 $237.5 million sub-limit for currency inconvertibility. In addition,

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the Company has a separate policy with OPIC, which provides $225 million of coverage, including a self-insured retention of $37.5 million, 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 when actions taken by the government of Egypt prevent Apache from exporting our share of production.

Non-GAAP Measures

The Company makes reference to some measures in discussion of its financial and operating highlights that are not required by or presented in accordance with GAAP. Management uses these measures in assessing operating results and believes the presentation of these measures provides information useful in assessing the Company s financial condition and results of operations. These non-GAAP measures should not be considered as alternatives to GAAP measures and may be calculated differently from, and therefore may not be comparable to, similarly titled measures used at other companies.

Adjusted Earnings

To assess the Company s operating trends and performance, management uses Adjusted Earnings, which is net income excluding certain items that management believes affect the comparability of operating results. Management believes this presentation may be useful to investors who follow the practice of some industry analysts who adjust reported company earnings for items that may obscure underlying fundamentals and trends. The reconciling items below are the types of items management excludes and believes are frequently excluded by analysts when evaluating the operating trends and comparability of the Company s results.

	For the Year Ended December 31,		
	2011	2010	2009
	(In millions, except share data)		
Income (Loss) Attributable to Common Stock (GAAP)	$ 4,508	$ 3,000	$ (292)
Adjustments:			
United Kingdom tax rate increase impact	218		
Oil & gas asset impairment of Chile, net of tax	60		
Merger, acquisitions & transition costs, net of tax	13	120	
Unrealized foreign currency fluctuation impact on deferred tax expense	(73)	52	198
Deferred tax adjustments	(75)		
U.S. and Canada proved property write-down, net of tax			1,981
Adjusted Earnings (Non-GAAP)	$ 4,651	$ 3,172	$ 1,887
Net Income (Loss) per Common Share Diluted (GAAP)	$ 11.47	$ 8.46	$ (0.87)
Adjustments:			
United Kingdom tax rate increase impact	.55		
Oil & gas asset impairment of Chile, net of tax	.15		
Merger, acquisitions & transition costs, net of tax	.03	.33	
Unrealized foreign currency fluctuation impact on deferred tax expense	(.18)	.15	.59
Deferred tax adjustments	(.19)		
U.S. and Canada proved property write-down, net of tax			5.87
Adjusted Earnings Per Share Diluted (Non-GAAP)	$ 11.83	$ 8.94	$ 5.59

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Critical Accounting Policies and Estimates

Apache prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States of America, which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. Apache identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of Apache s financial condition, results of operations, or liquidity and the degree of difficulty, subjectivity, and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection, and disclosure of each of the critical accounting policies. The following is a discussion of Apache s most critical accounting policies.

Reserves Estimates

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.

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.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a ceiling limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reserves as of December 31, 2011, 2010, and 2009, were calculated using 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.

Apache has elected not to disclose probable and possible reserves or reserve estimates in this filing.

Asset Retirement Obligation (ARO)

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Apache s removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with Apache s oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Income Taxes

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions worldwide. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

The Company regularly assesses and, if required, establishes accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions in countries where the Company operates. Tax reserves have been established and include any related interest, despite the belief by the Company that certain tax positions meet certain legislative, judicial, and regulatory requirements. These reserves are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, case law, and any new legislation. The Company believes that the reserves established are adequate in relation to the potential for any additional tax assessments.

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill.

The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company s assets and liabilities and tax-related carryforwards at the merger date, although such estimates may change in the future as additional information becomes known. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed relative to the total acquisition cost.

In estimating the fair values of assets acquired and liabilities assumed, we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves as described above in Reserve Estimates of this Item 7. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future.

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ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil, gas, and NGL prices, interest rates, or foreign currency and adverse governmental actions. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Risk

The Company s revenues, earnings, cash flow, capital investments, and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas, and NGLs, which have historically been very volatile due to unpredictable events such as economic growth or retraction, weather, and political climate. In 2011, our average worldwide crude oil realizations saw a significant increase from $91.74 per barrel in January to $110.98 in April, followed by a decrease to $97.88 in August. In 2011, crude oil prices averaged $102.19 per barrel, up 33 percent from 2010. Apache s average worldwide natural gas price realizations remained within a $0.44 range during 2011, with a high of $4.58 per Mcf in June and July, as compared to a $0.95 range during 2010. Average realized prices in 2011 for natural gas increased five percent to $4.37 per Mcf.

We periodically enter into hedging activities on a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to support oil and natural gas prices at targeted levels and to manage our overall exposure to oil and gas price fluctuations. In 2011, approximately 16 percent of our natural gas production and 29 percent of our crude oil production was subject to financial derivative hedges, compared with 23 percent and 12 percent, respectively, in 2010.

Apache may use futures contracts, swaps, options, and fixed-price physical contracts to hedge its commodity prices. Realized gains or losses from the Company s price-risk management activities are recognized in oil and gas production revenues when the associated production occurs. Apache does not hold or issue derivative instruments for trading purposes.

On December 31, 2011, the Company had open natural gas derivative hedges in an asset position with a fair value of $426 million. A 10-percent increase in natural gas prices would reduce the fair value by approximately $39 million, while a 10-percent decrease in prices would increase the fair value by approximately $38 million. The Company also had open crude oil derivatives in a liability position with a fair value of $248 million. A 10-percent increase in oil prices would increase the liability by approximately $193 million, while a 10-percent decrease in prices would decrease the liability by approximately $170 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2011. For notional volumes and terms associated with the Company s derivative contracts, please see Note 3 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Apache conducts its risk management activities for its commodities under the controls and governance of its risk management policy. The Risk Committee approves and oversees these controls, which have been implemented by designated members of the treasury department. The treasury and accounting departments also provide separate checks and reviews on the results of hedging activities. Controls for our commodity risk management activities include limits on credit, limits on volume, segregation of duties, delegation of authority and a number of other policy and procedural controls.

Interest Rate Risk

The Company considers its interest rate risk exposure to be minimal as a result of fixing interest rates on approximately 99.6 percent of the Company s debt. At December 31, 2011, total debt included $31 million of floating-rate debt. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $742,000.

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Foreign Currency Risk

The Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. In Australia, oil production is sold under U.S. dollar contracts, and gas production is sold largely under fixed-price Australian dollar contracts. Approximately half the costs incurred for Australian operations are paid in U.S. dollars. In Canada, oil and gas prices and costs, such as equipment rentals and services, are generally denominated in Canadian dollars but heavily influenced by U.S. markets. Our North Sea production is sold under U.S. dollar contracts, and the majority of costs incurred are paid in British pounds. In Egypt, all oil and gas production is sold under U.S. dollar contracts, and the majority of the costs incurred are denominated in U.S. dollars. Argentine revenues and expenditures are largely denominated in U.S. dollars, but are converted into Argentine pesos at the time of payment. Revenue and disbursement transactions denominated in Australian dollars, Canadian dollars, British pounds, and Argentine pesos are converted to U.S. dollar equivalents based on the average exchange rates during the period.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of Other under Revenues and Other or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company s provision for income tax expense on the Statement of Consolidated Operations. A 10-percent strengthening or weakening of the Australian dollar, Canadian dollar, British pound, and Argentine peso as of December 31, 2011, would result in a foreign currency net loss or gain, respectively, of approximately $150 million.

Forward-Looking Statements and Risk

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2011, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, p continue or similar terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- the market prices of oil, natural gas, NGLs, and other products or services;
- our commodity hedging arrangements;
- the integration of acquisitions;
- the supply and demand for oil, natural gas, NGLs, and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions;

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- the availability of capital resources;
- capital expenditure and other contractual obligations;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the availability of goods and services;
- legislative or regulatory changes;
- the impact on our operations due to the change in government in Egypt;
- terrorism or cyber-attacks;
- occurrence of property acquisitions or divestitures;
- the securities or capital markets and related risks such as general credit, liquidity, market and interest rate risks; and
- other factors disclosed under Items 1 and 2 Business and Properties Estimated Proved Reserves and Future Net Cash Flows, Item 1A Risk Factors, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this Form 10-K.

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

The financial statements and supplementary financial information required to be filed under this Item 8 are presented on pages F-1 through F-71 in Part IV, Item 15 of this Form 10-K and are incorporated herein by reference.

ITEM 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

The financial statements for the fiscal years ended December 31, 2011, 2010, and 2009, included in this report, have been audited by Ernst & Young LLP, registered public accounting firm, as stated in their audit report appearing herein.

ITEM 9A. ***CONTROLS AND PROCEDURES***

Disclosure Controls and Procedures

G. Steven Farris, the Company s Chairman and Chief Executive Officer, in his capacity as principal executive officer, and Thomas P. Chambers, the Company s Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2011, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company s disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the Commission s rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure. We also made no changes in internal controls over financial reporting during the quarter ending December 31, 2011, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

We periodically review the design and effectiveness of our disclosure controls, including compliance with various laws and regulations that apply to our operations both inside and outside the United States. We make modifications to improve the design and effectiveness of our disclosure controls and may take other corrective action, if our reviews identify deficiencies or weaknesses in our controls.

Management s Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Report of Management on Internal Control Over Financial Reporting, included on Page F-1 in Part IV, Item 15 of this Form 10-K.

The independent auditors attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to the Report of Independent Registered Public Accounting Firm, included on Page F-3 in Part IV, Item 15 of this Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2011, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

None.

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PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE*

The information set forth under the captions Nominees for Election as Directors, Continuing Directors, Executive Officers of the Company, and Securities Ownership and Principal Holders in the proxy statement relating to the Company s 2012 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, we are required to adopt a code of business conduct and ethics for our directors, officers, and employees. In February 2004, the Board of Directors adopted the Code of Business Conduct (Code of Conduct), and revised it in November 2011. The revised Code of Conduct also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access the Company s Code of Conduct on the Governance page of the Company s website at www.apachecorp.com. Any shareholder who so requests may obtain a printed copy of the Code of Conduct by submitting a request to the Company s corporate secretary at the address on the cover of this Form 10-K. Changes in and waivers to the Code of Conduct for the Company s directors, chief executive officer and certain senior financial officers will be posted on the Company s website within five business days and maintained for at least 12 months.

ITEM 11. *EXECUTIVE COMPENSATION*

The information set forth under the captions Compensation Discussion and Analysis, Summary Compensation Table, Grants of Plan Based Awards Table, Outstanding Equity Awards at Fiscal Year-End Table, Option Exercises and Stock Vested Table, Non-Qualified Deferred Compensation Table, Employment Contracts and Termination of Employment and Change-in-Control Arrangements and Director Compensation Table in the Proxy Statement is incorporated herein by reference.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The information set forth under the captions Securities Ownership and Principal Holders and Equity Compensation Plan Information in the Proxy Statement is incorporated herein by reference.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information set forth under the captions Certain Business Relationships and Transactions and Director Independence in the Proxy Statement is incorporated herein by reference.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

The information set forth under the caption Independent Auditors in the Proxy Statement is incorporated herein by reference.

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PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a) Documents included in this report:

1. Financial Statements

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company s financial statements and related notes.

3. Exhibits

EXHIBIT NO.	DESCRIPTION
2.1	Agreement and Plan of Merger, dated April 14, 2010, by and among Registrant, ZMZ Acquisitions LLC, and Mariner Energy, Inc. (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K, dated April 14, 2010, filed April 16, 2010, SEC File No. 001-4300) (the schedules and annexes have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.2	Amendment No. 1, dated August 2, 2010, to Agreement and Plan of Merger, dated April 14, 2010, by and among Registrant, ZMZ Acquisitions LLC, and Mariner Energy, Inc. (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K, dated August 2, 2010, filed on August 3, 2010, SEC File No. 001-4300) (the schedules and annexes have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.3	Purchase and Sale Agreement by and between BP America Production Company and ZPZ Delaware I LLC dated July 20, 2010 (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No.

001-4300) (the exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K).

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EXHIBIT NO.	DESCRIPTION
2.4	Partnership Interest and Share Purchase and Sale Agreement by and between BP Canada Energy and Apache Canada Ltd. dated July 20, 2010 (incorporated by reference to Exhibit 2.2 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No. 001-4300) (the exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
2.5	Purchase and Sale Agreement by and among BP Egypt Company, BP Exploration (Delta) Limited and ZPZ Egypt Corporation LDC dated July 20, 2010 (incorporated by reference to Exhibit 2.3 to Registrant s Current Report on Form 8-K/A, dated July 20, 2010, filed on July 21, 2010, SEC File No. 001-4300) (the exhibits and schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K).
3.1	Restated Certificate of Incorporation of Registrant, dated February 23, 2010, as filed with the Secretary of State of Delaware on February 23, 2010 (incorporated by reference to Exhibit 3.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2009, SEC File No. 001-4300).
3.2	Certificate of Designations of the 6.00% Mandatory Convertible Preferred Stock, Series D (incorporated by reference to Exhibit 3.3 to Registrant s Registration Statement on Form 8-A, dated July 29, 2010, SEC File No. 001-4300).
3.3	Amendment to Restated Certificate of Incorporation of Registrant, dated May 5, 2011, as filed with the Secretary of State of Delaware on May 5, 2011 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed May 11, 2011, SEC File No. 001-4300).
3.4	Bylaws of Registrant, as amended July 21, 2011 (incorporated by reference to Exhibit 3.1 to Registrant s Current Report on Form 8-K filed July 27, 2011, SEC File No. 001-4300).
4.1	Form of Certificate for Registrant s Common Stock (incorporated by reference to Exhibit 4.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, SEC File No. 001-4300).
4.2	Form of Certificate for the 6.00% Mandatory Convertible Preferred Stock, Series D(incorporated by reference to Exhibit A of Exhibit 3.3 to Registrant s Registration Statement on Form 8-A, dated July 29, 2010, SEC File No. 001-4300).
4.3	Form of 3.625% Notes due 2021 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).

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EXHIBIT NO.	DESCRIPTION
4.4	Form of 5.250% Notes due 2042 (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.5	Form of 5.100% Notes due 2040 (incorporated by reference to Exhibit 4.1 to Registrant s Current Report on Form 8-K, dated August 17, 2010, filed on August 20, 2010, SEC File No. 001-4300).
4.6	Rights Agreement, dated January 31, 1996, between Registrant and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.), rights agent, relating to the declaration of a rights dividend to Registrant s common shareholders of record on January 31, 1996 (incorporated by reference to Exhibit (a) to Registrant s Registration Statement on Form 8-A, dated January 24, 1996, SEC File No. 001-4300).
4.7	Amendment No. 1, dated as of January 31, 2006, to the Rights Agreement dated as of December 31, 1996, between Apache Corporation, a Delaware corporation, and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.) (incorporated by reference to Exhibit 4.4 to Registrant s Amendment No. 1 to Registration Statement on Form 8-A, dated January 31, 2006, SEC File No. 001-4300).
4.8	Senior Indenture, dated February 15, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank), formerly known as The Chase Manhattan Bank, as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.9	First Supplemental Indenture to the Senior Indenture, dated as of November 5, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.10	Form of Indenture among Apache Finance Pty Ltd, Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Registrant s Registration Statement on Form S-3, dated November 12, 1997, Reg. No. 333-339973).

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EXHIBIT NO.	DESCRIPTION
4.11	Form of Indenture among Registrant, Apache Finance Canada Corporation and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to Registrant s Registration Statement on Form S-3, dated November 12, 1999, Reg. No. 333-90147).
4.12	Deposit Agreement, dated as of July 28, 2010, between Registrants and Wells Fargo Bank, N.A., as depositary, on behalf of all holders from time to time of the receipts issued there under (incorporated by reference to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated July 22, 2010, filed on July 28, 2010, SEC File No. 001-4300).
4.13	Form of Depositary Receipt for the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.2 to Registrant s Current Report on Form 8-K, dated July 22, 2010, filed on July 28, 2010, SEC File No. 001-4300).
4.14	Senior Indenture, dated May 19 2011, between Registrant and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Corporation (incorporated by reference to Exhibit 4.14 to Registrant s Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.15	Senior Indenture, dated May 19, 2011, among Apache Finance Pty Ltd, Apache Corporation, as guarantor, and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Finance Pty Ltd and the related guarantees (incorporated by reference to Exhibit 4.16 to Registrant s Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.16	Senior Indenture, dated May 19, 2011, among Apache Finance Canada Corporation, Apache Corporation, as guarantor, and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Finance Corporation and the related guarantees (incorporated by reference to Exhibit 4.20 to Registrant s Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.17	Form of Apache Corporation November 10, 2010 First Non-Qualified Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).

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EXHIBIT NO.	DESCRIPTION
4.18	Form of Apache Corporation November 10, 2010 Second Non-Qualified Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).
4.19	Form of Apache Corporation November 10, 2010 Non-Statutory Stock Option Agreement for Certain Employees of Apache Corporation (incorporated by reference to Exhibit 4.8 to Registrant s Registration Statement on Form S-8 filed on November 10, 2010, Reg. No. 333-170533).
10.1	Form of Amended and Restated Credit Agreement, dated as of May 9, 2006, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).
10.2	Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of April 5, 2007, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300).
10.3	Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of February 18, 2008, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300).
10.4	Form of Credit Agreement, dated as of May 12, 2005, among Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, J.P. Morgan Securities Inc. and Banc of America Securities, LLC, as Co-Lead Arrangers and Joint Bookrunners, Bank of America, N.A. and Citibank, N.A., as U.S. Co-Syndication Agents, and Calyon New York Branch and Société Générale, as U.S. Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.01 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).

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EXHIBIT NO.	DESCRIPTION
10.5	Form of Credit Agreement, dated as of May 12, 2005, among Apache Canada Ltd, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, RBC Capital Markets and BMO Nesbitt Burns, as Co-Lead Arrangers and Joint Bookrunners, Royal Bank of Canada, as Canadian Administrative Agent, Bank of Montreal and Union Bank of California, N.A., Canada Branch, as Canadian Co-Syndication Agents, and The Toronto-Dominion Bank and BNP Paribas (Canada), as Canadian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.02 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
10.6	Form of Credit Agreement, dated as of May 12, 2005, among Apache Energy Limited, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, Citi securities Limited, as Australian Administrative Agent, Deutsche Bank AG, Sydney Branch, and JPMorgan Chase Bank, as Australian Co-Syndication Agents, and Bank of America, N.A., Sydney Branch, and UBS AG, Australia Branch, as Australian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.03 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
10.7	Form of Request for Approval of Extension of Maturity Date and Amendment, dated April 5, 2007, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.6 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300).
10.8	Form of Request for Approval of Extension of Maturity Date and Amendment, dated February 18, 2008, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300).
10.9	Credit Agreement, dated August 13, 2010, among Registrant, JP Morgan Chase Bank, N.A., as Administrative Agent, and Citibank, N.A., Bank Of America, N.A. and Goldman Sachs Bank USA, as Co-Syndication Agents, J.P. Morgan Securities Inc., Citigroup Global Markets Inc., Banc Of America Securities, LLC and Goldman Sachs Bank USA, As Co-Lead Arrangers and Joint Bookrunners, and the lenders party thereto (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K filed August 16, 2010).

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EXHIBIT

NO.