APACHE CORP
Form 10-K
February 28, 2011

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

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-4300

APACHE CORPORATION
(Exact name of registrant as specified in its charter)

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

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400
(Address of principal executive offices)
Registrant s telephone number, including area code **(713) 296-6000**
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange On Which Registered**
Common Stock, $0.625 par value	New York Stock Exchange, Chicago Stock Exchange and NASDAQ National Market
Preferred Stock Purchase Rights	New York Stock Exchange and Chicago Stock Exchange
Apache Finance Canada Corporation 7.75% Notes Due 2029 Irrevocably and Unconditionally Guaranteed by Apache Corporation	New York Stock Exchange
Depositary Shares Representing a 1/20th Interest in a Share of 6.00% Mandatory	New York Stock Exchange

Convertible Preferred Stock, Series D

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 þ No o

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 þ No o

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. þ

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2010	$ 28,439,311,280
Number of shares of registrant s common stock outstanding as of January 31, 2011	382,752,217

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s proxy statement relating to registrant s 2011 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 Bbl 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, which is approximately equal to one Mcf.

LIBOR means London Interbank Offered Rate.

LNG means liquefied natural gas.

Mb/d means Mbbls per day.

Mbbls means thousand barrels of oil.

Mboe means thousand boe.

Mboe/d means Mboe per day.

Mcf means thousand cubic feet of natural gas.

Mcf/d means Mcf per day.

MMbbls means million barrels of oil.

MMboe means million boe.

MMBtu means million Btu.

MMBtu/d means MMBtu per day.

MMcf means million cubic feet of natural gas.

MMcf/d means MMcf per day.

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

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

PUD means proved undeveloped.

SEC means United States Securities and Exchange Commission.

Tcf means trillion cubic feet.

U.K. means United Kingdom.

U.S. means United States.

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

PART I

ITEMS 1 AND 2. *BUSINESS AND PROPERTIES*

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Part II, Item 7A 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 seven countries: the U.S., Canada, Egypt, Australia, offshore the United Kingdom in the North Sea, Argentina, and Chile.

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 25, 2010, 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 Apache s corporate governance (including our Code of Business Conduct and Governance Principles) and documents Apache files 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.

We hold interests in many of our U.S., Canadian and other international properties through subsidiaries. Properties to which we refer in this document may be held by those subsidiaries. We treat all operations as one line of business. 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 stockholders. Apache s long-term perspective has many dimensions, with the following core strategic components:

balanced portfolio of core assets;

conservative capital structure; and

rate of return focus.

Throughout the cycles of our industry, these strategies have underpinned our ability to deliver long-term production and reserve growth and achieve competitive investment rates of return for the benefit of our shareholders. We have increased reserves 22 out of the last 25 years and production 30 out of the past 32 years, a testament to our consistency over the long-term.

Apache pursues opportunities for growth through exploration and development drilling, supplemented by occasional strategic acquisitions. In the years immediately prior to 2010, we were relatively absent from the acquisition market. We believed the market was overheated as oil and gas prices spiked, and the opportunities we identified did not meet our criteria for risk, reward, rate of return and/or growth potential. We built our cash position while drilling from our existing inventory of prospects and waiting for the right transactions to add to our portfolio. During 2010 we completed more than $11 billion in acquisitions and made significant progress with exploitation on existing core properties.

The current-year acquisitions fit well with our long-term strategy of maintaining a balanced portfolio of core assets. They included high-quality assets with a diversity of geologic and geographic risk, product mix and reserve life. The properties are strategically positioned with our existing infrastructure and play to the strengths that come with our experience operating in the Permian Basin, Canada and Gulf of Mexico (GOM). The Mariner merger also provided a strategic position in the deepwater GOM, which is relatively under explored and oil prone and gives Apache exposure to significant domestic oil reserves. The transactions drove a 42 percent, or 10 million acre, year-over-year increase in our undeveloped gross acres, adding to our inventory of future drilling and exploration opportunities.

2010 Acquisitions

North America

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. 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.

International

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

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 seven countries, spanning five continents: the Gulf Coast, Permian and Central regions of the U.S., Canada, Egypt, the U.K. North Sea, Australia, Argentina and on the Chilean side of the island of Tierra del Fuego. Our 2010 acquisitions added to our asset base in the United States, Canada, and Egypt.

In addition, each of our producing regions has achieved an economy of scale providing a vehicle for cost-effective base production and a combination of lower- and medium-risk drilling opportunities. The net cash provided by operating activities (cash flows) generated by our current production base funds our drilling and development capital program, giving us the ability to pursue new exploration targets over our 35 million gross undeveloped acres across the globe and develop our pipeline of exploration discoveries. Those developments will fund the next round of exploration activities and development programs.

In 2010:

- No single region contributed more than 28 percent of our equivalent production or revenue.
- No single region held more than 26 percent of our year-end estimated proved reserves.

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The mixture of reserve life (estimated reserves divided by annual production) in our countries, which translates into balance in the timing of returns on our investments, ranges from as short as five years to as long as 25 years.

Our balanced product mix provides a measure of protection against price deterioration in a given product while retaining upside potential through a significant increase in either commodity price. In 2010 crude oil and liquids provided 52 percent of our production and 77 percent of our revenue.

At year-end our estimated proved reserves were 44 percent crude oil and liquids and 56 percent natural gas.

Our international gas portfolio, which accounted for 19 percent of our 2010 worldwide equivalent production, positions us to take advantage of increasing prices in Argentina and Australia.

Conservative Capital Structure

Maintaining a strong balance sheet and financial flexibility is a core strategic component of our long-term strategy. We believe our balance sheet, and the financial flexibility it provides, is one of our most important strategic assets. Maintaining a strong balance sheet 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, as they did in 2010.

We exited 2010 with a debt-to-capitalization ratio of 25 percent, an increase of only one percent despite current year capital investments of $17 billion, and $2.4 billion of available committed borrowing capacity.

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, strict cost control, and the creative application of technology.

Our centralized management and incentive systems provide a uniform process of measuring success across Apache. They incentivize high rate-of-return activities but allow for appropriate risk-taking to drive future growth. Results of operations and rates 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 flow. We do this through a disciplined and focused process that includes analyzing current economic conditions, projected rates 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.

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.

One such example is a manifold developed for our Horn River Shale gas play in northeast British Columbia, where Apache is employing pad-drilling technology. Apache engineers developed and applied for a patent on a manifold that can connect all horizontal wells on a single pad, driving down costs by reducing non-productive time on our 24-hour-a-day hydraulic fracturing operations. This technology will reduce costs and increase Apache s rate of return on potentially thousands of future wells across our leasehold.

At our Forties field in the North Sea, Apache is using techniques that bring together many sources of data to give an accurate view of the current state of the field and identify likely places to find unswept oil deposits. Four-dimensional modeling, which uses reservoir engineering data and a series of 3-D seismic surveys, is utilized by Apache to create a time-lapse picture that shows where oil remains after more than 35 years of production. The latest model of the reservoir highlights the potential for stranded oil accumulations and enhances the success of the ongoing drilling program as well as identifies new potential drilling locations.

For a more in-depth discussion of our 2010 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 seven countries: the U.S., Canada, Egypt, Australia, offshore the United Kingdom in the North Sea, Argentina, and Chile.

The following table sets out a brief comparative summary of certain key 2010 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2010 Production (In MMboe)	Percentage of Total 2010 Production	2010 Production Revenue (In millions)	12/31/10 Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	2010 Gross New Wells Drilled	2010 Gross New Productive Wells Drilled
United States	84.7	35%	$ 4,300	1,304	44%	410	388
Canada	30.5	13	1,074	757	26	182	173
Total North America	115.2	48	5,374	2,061	70	592	561
Egypt	59.0	24	3,372	307	10	204	177
Australia	28.9	12	1,459	314	11	31	23
North Sea	20.9	9	1,606	155	5	20	12
Argentina	16.0	7	372	116	4	56	52
Other International						1	1
Total International	124.8	52	6,809	892	30	312	265
Total	240.0	100%	$ 12,183	2,953	100%	904	826

North America

Apache s North American asset base comprises the Gulf Coast, Permian and Central regions of the U.S. and its operations in Canada. In 2010 our North America assets contributed 48 percent of our production and 44 percent of our oil and gas production revenues. At year-end 70 percent of our estimated proved reserves were located in North America.

United States

Overview We have 9.7 million gross acres across the U.S., approximately half of which is undeveloped. Approximately 30 percent of the undeveloped acreage is held-by-production. Our U.S. assets are located in the Gulf Coast, Permian and Central regions. The three regions provide our U.S. asset base with a balance of hydrocarbon mix and reserve life. In 2010 48 percent of our U.S. production and 58 percent of our U.S. year-end reserves were oil and liquids. In addition, the reserve life of our U.S. regions ranged from nine to 30 years with the Gulf Coast region s shorter-lived reserves balancing longer-lived reserves in the Central and Permian regions. In 2010 35 percent of

Apache s equivalent production and 44 percent of Apache s total year-end reserves were in the U.S.

Gulf Coast Region Our Gulf Coast assets are primarily located in and along the Gulf of Mexico, in the areas on- and offshore Texas and Louisiana. In 2010 the Gulf Coast region contributed approximately 19 percent of our worldwide production and revenues, predominately from offshore properties. Apache s Gulf Coast operations grew significantly during the year with the June acquisition of Devon s Gulf of Mexico shelf properties and the addition of properties with the Mariner merger in November 2010. These transactions were aligned with our long-term core strategy of maintaining a balanced portfolio of assets. The region accounted for nearly 13 percent of our estimated proved reserves at year-end compared to 13 percent the previous year.

Apache has been the largest offshore held-by-production acreage owner since 2004 and is now the largest producer in waters less than 500 feet deep (shelf). The Devon acquisition and Mariner merger brought significant development and exploration opportunities with high-quality assets complementary to our existing assets, as well as a strategic presence in the deepwater Gulf of Mexico (waters greater than 500 feet deep). The deepwater Gulf of Mexico is relatively underexplored and oil prone and provides exposure to significant reserve and production

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potential. Acreage increased 76 percent to 5.3 million gross acres: 2.5 million deepwater, 1.4 million shelf, and 1.4 million onshore. Over 50 percent of the region s acreage was undeveloped.

In 2010 the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) announced a series of moratoria, which directed oil and gas lessees and operators to cease drilling new deepwater (depths greater than 500 feet) wells on the Outer Continental Shelf (OCS), and put oil and gas lessees and operators on notice that, with certain exceptions, the BOEMRE would not consider drilling permits for deepwater wells and related activities. While the moratoria have been formally lifted, no new permits for deepwater drilling have been issued as of the date of this filing.

In addition, the BOEMRE issued new regulations in 2010 requiring additional information, documentation and analysis for all new wells on the OCS. The effect of these new regulations was to significantly slow down issuance of permits for shallow wells. Apache continues to operate under these new regulations and, through February 2011, has received 25 drilling permits for shallow wells. Current permitting activity has been slowed compared to prior-year levels, and the Company has budgeted its exploration and development activity accordingly.

Despite the curtailment of activity in the region stemming from new regulations, the region had a productive year, drilling or participating in 63 wells (36 in the Gulf of Mexico), up from 26 wells (20 in the Gulf of Mexico) in 2009, and performing 365 workovers and recompletions.

As a result of 2010 acquisitions and the differing growth and opportunity profiles, we have divided the assets into three regions beginning in 2011: Gulf of Mexico shelf, Gulf of Mexico deepwater and Gulf Coast onshore. In 2011 the Company plans to invest approximately $200 million, $1 billion and $500 million in the Gulf Coast onshore, Gulf of Mexico shelf and Gulf of Mexico deepwater assets, respectively, subject to receipt of permits from BOEMRE. The capital will be spent on drilling, recompletion and development projects, equipment upgrades, production enhancement projects, lease acquisition, seismic acquisition and abandonment activities.

On September 16, 2010, the BOEMRE and the Department of the Interior issued a Notice to Lessees and Operators (NTL) updating the procedures and timing for decommissioning offshore wells and platforms. While the so called Idle Iron NTL may result in an acceleration of timing to abandon certain wells and remove certain platforms in the Gulf of Mexico, our ongoing active well and equipment abandonment program mitigated the impact of the new regulations on Apache. The Company spent approximately $260 million to plug offshore wells and remove platforms in 2010. With the addition of the Devon and Mariner offshore properties, we currently plan to spend approximately $350 million in 2011.

Central Region The Central region includes nearly 2,000 wells and controls over one million gross acres primarily in western Oklahoma, the Texas panhandle and east Texas. Most of the region s acreage is held-by-production. Although the reserves and production are primarily natural gas, given the price disparity between oil and gas, the region successfully targeted oil and liquids rich gas plays in 2010. Oil-and liquids-production increased by 54 percent and 90 percent, respectively, over the prior year. In 2010 Apache drilled or participated in the drilling of 84 wells, 99 percent of which were completed as producers. The region also performed 144 workovers and recompletions. The region s year-end estimated proved reserves, which were 90 percent natural gas, were six percent of Apache s total.

In the Anadarko basin, the Granite Wash play has long been a core stacked-pay target for the region, where we have drilled many vertical wells over the past several decades. As a result, we control approximately 200,000 gross acres in this liquid-rich play, mostly held-by-production. Despite the numerous vertical wells drilled, the Granite Wash is re-emerging as a horizontal play that is capitalizing on advances in horizontal drilling and fracturing technology and high oil prices given the rich liquids yield of the wells. In 2009 we drilled our first operated horizontal well in the Granite Wash. In 2010 we ramped up activity to 10 rigs, drilling 31 horizontal Granite Wash wells and testing six additional horizons including the Hogshooter interval, which is shallower, younger and oilier than previously tested Granite Wash targets. We have completed two wells in the Hogshooter interval, which are separated by over fifteen miles of what appears to be very prolific acreage, primarily owned and operated by Apache. We have identified hundreds of additional Granite Wash horizontal well locations across our acreage. In 2011 we plan to keep a minimum of eight rigs running in this play and drill in excess of 40 horizontal wells, targeting several horizons.

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We have had success on the Anadarko shelf drilling relatively shallow horizontal wells into the Cherokee formation. In 2010 we completed four horizontal wells in the Cherokee play with vertical depths of 6,500 feet and horizontal penetrations of nearly one mile. These wells had average 30-day rates of 520 b/d and 850 Mcf/d and an average Apache working interest of 78 percent**.** The wells are currently producing an average of 150 b/d and 560 Mcf/d. We plan to drill 13 horizontal wells in the Cherokee in 2011. In addition, we have had success with our program targeting oil in Ochiltree County, Texas. During the year we drilled four wells in the Cleveland formation at a vertical depth of 7,500 feet and participated in one horizontal well in the Marmaton formation at a depth of 11,000 feet. Two of the Cleveland wells and the Marmaton well commenced production in late 2010 at an average initial rate of approximately 500 b/d. Apache s average working interest in the five wells is 90 percent. The two remaining Cleveland wells are awaiting completion, and we intend to keep at least one drilling rig running in the area throughout the year.

We are also employing horizontal drilling and multistage fracture technology in east Texas. In 2010 we drilled seven horizontal Bossier wells in Freestone County, Texas, where we own 45,000 gross acres. The wells produced an aggregate 7.34 Bcf during the year and are currently producing 37 MMcf/d, 33 MMcf/d net to Apache.

In 2011 the Central region plans to invest approximately $430 million in drilling, recompletions, equipment upgrades, production enhancement projects and lease acquisitions, primarily in the Anadarko basin. We currently plan to keep 12 rigs running all year, with more than 95 percent of the wells drilled horizontally and 89 percent of the wells drilled targeting oil or high liquid yield gas.

Permian Region Our Permian region, carved out of our Central region, grew significantly in 2010. In July we opened a new regional office in Midland. The region s property and acreage base increased substantially upon completion of the BP acquisition in July and the Mariner merger in November. These two transactions combined added approximately 35 Mboe/d of new production and more than doubled our acreage to over three million gross acres with exposure to every known play in the Permian Basin. The drilling rig count has increased from five operating at the beginning of 2010 to more than 20 at the end of the year. The workover and completion rig count has increased from 56 to 80, and the employee headcount in Midland and the field has increased by more than 200 during this same time period. The region drilled or participated in 263 wells and completed approximately 1,100 workovers and recompletions in 2010.

Apache is one of the largest operators in the Permian Basin, operating more than 11,000 wells in 152 fields, including 45 waterfloods and six CO_2 floods. Fourth-quarter net production was 59 Mb/d and 162 MMcf/d and included only six weeks of production from the properties acquired in the Mariner merger. The Permian region s year-end estimated proved reserves, which were 76 percent oil and liquids, were 25 percent of Apache s total.

During 2010 the Permian region tested horizontal drilling opportunities in four mature waterflood fields, the North McElroy, Shafter Lake, TXL South, and Dean Units, all of which resulted in commercial successes. The region ultimately drilled and completed a total of 17 horizontal wells in the units. The Midland team has developed a significant inventory of potential horizontal drilling applications on existing Apache acreage across the Permian Basin. In 2011 we plan to drill 41 horizontal wells across a number of the region s assets.

In 2010 the region signed a 20-year CO_2 supply contract to develop approximately 8.4 MMboe of estimated proved reserves at Roberts Unit. Our 2010 drilling results at Roberts Unit include 15 production and CO_2 injection wells that resulted in higher than predicted production rates. The CO_2 development at Roberts Unit will continue during 2011 with 43 new production and injection wells planned.

In 2011 the Permian Region plans to invest approximately $930 million in drilling, recompletion projects, equipment upgrades, expansion of existing facilities and equipment and leasing new acreage. We plan to keep more than 20 rigs running all year drilling an estimated 368 wells. The region s 2011 drilling activity will focus on a combination of Apache legacy assets and the newly acquired Mariner and BP properties. On the BP properties alone, the region has identified more than 2,000 drilling locations. Current plans include 130 wells in the Deadwood area (acquired from Mariner) where we hold 63,000 net acres subject to continuous drilling clauses and in the Empire Yeso area (acquired from BP), where we plan to drill approximately 55 wells.

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.

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.

Canada

Overview Apache has 6.3 million net acres across the provinces of British Columbia, Alberta and Saskatchewan, including approximately 1.3 million net mineral and leasehold acres in Western Alberta and British Columbia acquired from BP in 2010. 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 2010 our Canadian region held approximately 26 percent of our estimated proved reserves. In 2010 we drilled or participated in 182 wells in Canada, eight of which were exploratory wells. The region s 2010 natural gas production increased ten percent, while liquids production was one percent higher.

On our conventional assets, we are focused on oil projects located primarily in Alberta and Saskatchewan, enabling us to take advantage of the current strong oil prices. We will utilize our drilling technology and reservoir modeling expertise to identify and exploit unswept oil in our waterflood projects in the House Mountain, Leduc and Snipe Lake fields. Additional drilling for oil will continue on our enhanced oil recovery projects in Midale and Provost with long-term plans to develop and expand waterfloods and CO_2 projects. We will also continue intermediate-depth gas development drilling in Kaybob and West 5 areas.

Apache s near-term natural gas production growth will likely be driven by our activity in two large growth plays in British Colombia: shale gas in the Horn River basin and tight sands in the Noel area. In the Horn River basin, Apache has a 50-percent interest and 210,000 net acres. During 2010 Apache reached a peak of 100 MMcf/d net, drilled 29 new wells and completed 30 wells. In 2011 we plan to drill 10 and complete 28 wells in the Horn River basin. Apache acquired its 100-percent working interest in the Noel area from BP in October 2010. Gas production from Noel reached an exit rate of 100 MMcf/d in December 2010. In 2011 we are currently planning a horizontal drilling program of approximately 11 wells in the Noel Area. Apache has identified many years of drilling activity in both plays.

During the first quarter of 2010 Apache Canada Ltd. (Apache Canada), through its subsidiaries, purchased a 51 percent interest in a planned LNG export terminal (Kitimat LNG facility) and a 25.5-percent interest in a partnership that owns a related proposed pipeline. In the second quarter of 2010 EOG Resources Canada, Inc. (EOG Canada), through its wholly-owned subsidiaries, acquired the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the pipeline partnership from Pacific Northern Gas Ltd. (PNG). Under the terms of the agreement, PNG will operate and maintain the planned pipeline under a seven-year agreement with Apache Canada and EOG Canada with provisions for five-year renewals. It also includes a 20-year transportation service arrangement which may require Apache Canada and EOG Canada, under certain circumstances, to use a portion of PNG s current pipeline capacity. Upon close of the transaction, expected in the second quarter of 2011, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the pipeline partnership and proposed pipeline.

Apache Canada and EOG Canada 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 five million metric tons of LNG per year, of which Apache Canada has reserved 51 percent. The proposed 287-mile pipeline 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. Apache Canada will have rights to 51-percent of the capacity in the proposed pipeline. Completion of the front-end engineering and design (FEED) study and a final investment decision are targeted for late 2011. Construction is expected to commence in 2012, with commercial operations projected to begin in 2015.

Our plans for 2011 are to drill or participate in a total of 149 wells in Canada, including 129 development wells and 20 exploratory wells. The planned development includes nine drills and 28 completions in the Horn River basin.

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During 2011 the region plans to invest approximately $800 million for drilling and development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately $25 million is allocated for Gathering, Transmission and Processing (GTP) assets.

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 the concentration of credit risk in our portfolio. To diversify our market exposure, we transport natural gas via our firm transportation contracts to California, the Chicago area and eastern Canada. We sell the majority of our Canadian gas on a monthly basis at either first-of-the-month or daily prices. In 2010 approximately two percent of our gas sales were subject to long-term fixed-price contracts, with the latest expiration in 2011.

Our Canadian crude is sold primarily to integrated major oil companies and marketers. We sell our oil based on West Texas Intermediate (WTI) and sell our NGLs based on postings or a percentage of WTI. Prices are 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. We transport crude oil on 12 pipelines to the major trading hubs within Alberta and Saskatchewan, which enables us to achieve a higher netback for the production and to diversify our purchasers.

International

Apache s international assets are located in Egypt, Australia, offshore the U.K. in the North Sea, Argentina and Chile. In 2010 international assets contributed 52 percent of our production and 56 percent of our oil and gas production revenues. At year-end 30 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 11.3 million gross acres making Apache the largest acreage holder in Egypt s Western Desert. Only 15 percent of our gross acreage in Egypt has been developed. That 15 percent produced an average of 189 Mb/d and 799 MMcf/d in 2010, 99 Mb/d and 375 MMcf/d net to Apache, which we believe 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 85 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 68 percent of our acreage. In 2010 the region contributed 28 percent of our production revenue, 24 percent of our production and 10 percent of our year-end 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. A percentage of the production, 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. In 2010, Apache retained approximately 52 percent and 47 percent, respectively, of the gross oil and gas produced from our Egyptian concessions. 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 10 to 25 years.

Apache s Egyptian operations had another year of growth in 2010: gross daily production increased 16 percent, and net daily production increased six percent. We maintained an active drilling and development program, drilling 204 wells, including 10 new field discoveries, and conducted 662 workovers and recompletions. In addition, we achieved a goal we set in 2005 to double gross equivalent production from our operated concessions by the end of 2010. In November we closed on the purchase of BP assets in Egypt s Western Desert, acquiring four development leases and one exploration concession as well as strategically-positioned infrastructure that will enable Apache to increase production from existing fields in the Western Desert.

During 2011 the region plans to invest approximately $1.1 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 65 gross exploration wells, 50 percent more than 2010. We will also drill our first horizontal well in the Western Desert.

Egypt political unrest As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience in the Egyptian capital of Cairo that began on January 25, 2011, Egyptian president Hosni Mubarak stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces is now in power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and that the military would rule for six months until elections can be held. Following the advice of the U.S. State Department, Apache initially evacuated all non-essential personnel from Egypt. As conditions stabilized recently, approximately one-third of the evacuated employees returned. Apache s production, located in remote locations in the Western Desert, has continued uninterrupted; however, further changes 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 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 covering losses arising from confiscation, nationalization, and expropriation risks and currency inconvertibility. In addition, the Company has a separate policy with OPIC, which provides $300 million of coverage for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum when actions taken by the Government of Egypt prevent Apache form 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 a price cap) until 2013 for up to 100 MMcf/d gross. This region averaged $3.62 per Mcf in 2010.

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. In 2010 we sold 32 cargoes (approximately 10.1 MMbbls) of Western Desert crude oil into the export market from the El Hamra terminal located on the northern coast of Egypt. These export cargoes were sold to third parties at market prices above our domestic prices received from EGPC. Additionally, Apache sold Qarun oil (approximately 10.7 MMbbls) at the Sidi Kerir terminal, also located on the northern coast of Egypt. This Qarun oil was sold at prevailing market prices into the domestic market to non-governmental purchasers (1.3 MMbbls) or exported primarily to refiners in the Mediterranean region (15 cargoes for approximately 9.4 MMbbls).

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, the Exmouth basin and the Browse basin. We also have exploration acreage in the Gippsland basin offshore southeastern Australia. Production operations are concentrated in the Carnarvon and Exmouth basins. In total, we control approximately 12.2 million gross acres in Australia through 35 exploration permits, 14

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production licenses and six retention leases. In addition, we have one production license and four retention leases pending confirmation.

During the year the region participated in drilling 31 wells, of which 23 were productive. In addition, we expanded our exploration opportunities in the Carnarvon and Exmouth basins via farm-ins to seven permits. The transactions resulted in a 58-percent increase in our net undeveloped acreage in the Carnarvon basin and added 1.9 million net acres for exploration in the Exmouth basin. Oil production increased by 369 percent on initial production from the development of our 2007 Van Gogh and Pyrenees oil field discoveries, while gas production increased by nine percent. Production from Australia accounted for approximately 12 percent of our total 2010 production, and year-end estimated proved reserves were 11 percent of Apache s total.

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

In 2011, development of our Reindeer field discovery should be complete with first production expected late in the year upon completion of our Devil Creek Gas Plant. The plant will be Western Australia s third domestic natural gas processing hub and the first new one in more than 15 years. The two-train plant is designed to process 200 million cubic feet of gas per day from the Apache-operated Reindeer field. In 2009, we entered into a gas sales contract covering a portion of the field s future production. Under the contract, Apache and its joint venture partner agreed to supply 154 Bcf of gas over seven years (approximately 60 MMcf/d beginning in the fourth quarter of 2011) at prices substantially higher than we have historically received in Western Australia. Apache owns a 55-percent interest in the field. Also in 2011, initial production is projected from the Halyard-1 discovery well which is a subsea completion tied back to the existing gas facilities on Varanus Island.

In 2012, the 2010 Spar-2 discovery is projected to commence production through an extension of the Halyard sub sea infrastructure which will also allow for the tie-in of future wells.

In 2013, first production is projected from four gas wells completed in 2010 in the Macedon gas field. We have a 28 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; with first production projected in 2013.

Also in 2013 first production is projected from the Coniston oil field which lies just north of the Van Gogh field. The project was sanctioned for development in 2010. Current plans call for the field to be produced from subsea completions tied back to the Van Gogh field floating, production, storage and offloading (FPSO) Ningaloo Vision.

In 2014 first production from the Balnaves field is projected, should the project proceed past Final Investment Decision (FID) stage. The Balnaves field is an oil accumulation in the Brunello gas field, where Apache drilled three successful development wells which we plan to produce through a FPSO. The project is currently in the Front End FEED stage with FID currently projected for the second half of 2011.

In 2016 we are projecting to begin production from our operated Julimar and Brunello field gas discoveries through the Chevron operated Wheatstone LNG hub, in which we own a foundation equity partner interest of 13 percent. Apache s projected net gas sales from the fields are 160 MMcf/d and 3,250 b/d with a projected 15-year production plateau when the multi-year project is fully operational. The project, which is currently in FEED, will convert the gas into LNG for sale on the world market. World LNG prices are typically oil-linked prices and are currently higher than the historical gas prices in Western Australia. The project FID is scheduled for 2011, with first LNG projected in 2016.

During 2011 the region plans to invest approximately $1.2 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately half of the 2011 investment will be for development and processing facilities in connection with the projects discussed above.

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 escalation clauses based on either the Australian consumer price index or a commodity linkage. As of

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December 31, 2010, Apache had a total of 18 active gas contracts in Australia with expiration dates ranging from November 2012 to July 2030. 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 received on recent contracts, including our Reindeer field, are substantially higher than historical levels.

We anticipate selling LNG from our Julimar and Brunello field gas discoveries at prices tied to oil and sold into international markets.

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 a premium, which are typically 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). In 2010 the North Sea region produced 20.9 MMboe (99 percent oil), approximately nine percent of our total worldwide production and 13 percent of Apache s oil and gas production revenues. During 2010 production from Forties decreased seven percent compared to 2009 as natural well decline and unplanned maintenance downtime exceeded gains from drilling. At year-end 2010, Apache had total estimated proved reserves of 155 MMbbls of crude oil in this region, approximately five percent of our year-end estimated proved reserves. Apache acquired Forties with 45 producing wells. Today, there are 77 producing wells with an inventory of future locations. By the end of the first quarter of 2010, Apache had produced and sold, net to its interest, oil volumes in excess of the proved reserves booked when we acquired this interest in 2003.

During the summer of 2010 a new 3-D seismic survey was acquired in Forties. Comparison of this data with 3-D seismic shot in prior years has highlighted many areas of bypassed oil in the reservoir and provided better definition of existing targets. In 2010, 20 wells were drilled into the Forties reservoir, of which 12 were productive. We project that this Forties success rate of 60 percent will increase in the future, as drilling results from late December 2010 and early January 2011 have validated the new 4-D evaluation and geological interpretation. We also drilled three exploration wells and one development well outside Forties. The development well and one of the exploration wells were successful.

In 2011 the region will invest approximately $850 million on a diverse set of capital projects. Forties will see another year of active drilling with two platform rigs and a jack-up in operation. Construction of the Forties Alpha Satellite Platform is underway and is projected to be complete by mid-year 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. Also, during the third quarter of 2011 drilling will commence on the Bacchus field, Apache s first North Sea subsea field development. First production is projected by year-end of 2011. The region also expects to participate in at least two exploration wells outside Forties.

In January 2011 a subsea pipeline connecting our Forties Bravo platform to our Charlie platform was shut-in because of corrosion. A project is underway to re-route the production through a smaller line until a new flexible pipeline is installed. This intermediate solution should be completed by the first of March 2011 and will allow us to produce approximately half of the 11,600 b/d that flowed through the main pipeline. The new main subsea pipeline will be completed by September 2011.

Marketing In 2010 we sold our Forties crude under both term contracts (70 percent) and spot cargoes (30 percent). The term sales are composed of a market-based index 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 2011 production will be sold under a term contract with a per-barrel premium to the Dated Brent index. A separate physical sales contract within the term sale for 20,000 b/d was entered into with a floor price of $70.00 per barrel and an average ceiling price of $98.56 per barrel. This contract will be settled against Dated Brent.

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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 24 concessions, exploration permits and other interests totaling over 3.4 million gross acres (2.9 million net). Apache now holds oil and gas assets in three of the main Argentine hydrocarbon basins: Neuquén, Austral and Cuyo. Our concessions have varying expiration dates ranging from four years to over fifteen years remaining, subject to potential additional extensions. In 2010 Argentina produced seven percent of our worldwide production and held four percent of our estimated proved reserves at year-end.

In 2010 the region had its most successful development drilling program in its history, drilling 56 gross wells:; 43 in the Neuquén basin and 13 in the Austral basin of Tierra del Fuego. Drilling focused on shallow development targets, 93 percent of the wells were successful. In addition, the region completed 106 capital projects consisting of recompletions, increasing lifting capacity, and facility projects.

Also during 2010 Apache acquired approximately 567 square kilometers of 3-D seismic on two blocks located in the Cuyo basin. Apache employed new cable-less technology intended to minimize environmental impact in the area, the first time this technology has been used in Argentina. We are currently analyzing the results from the seismic shoot and expect to commence a drilling campaign in the Cuyo basin in the first quarter of 2011.

In 2011 we will begin negotiations for extensions of three concessions each in the Tierra del Fuego and Rio Negro Provinces, which are scheduled to expire in 2016 and 2017. Future investment by Apache in the Tierra del Fuego Province will be significantly influenced by the probability of obtaining the Province s agreement to an extension of the present concession expirations. In March 2009 Apache reached an agreement with the Province of Neuquén to extend eight federal oil and gas concessions for 10 additional years. The concessions, which were scheduled to expire between 2015 and 2017, encompass approximately 590,000 net acres, including exploratory areas totaling 514,000 net acres. Neuquén operations generate about half of Apache s total output in Argentina.

During 2011 the region plans to invest approximately $300 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, and seismic acquisition.

Marketing

Natural Gas Apache sells its natural gas through three avenues:

> Gas Plus program: This program was instituted by the Argentine government to encourage new gas supplies through the development of tight sands and unconventional reserves. Under this program, qualifying projects are allowed to sell gas at prices that are above the regulated rates. During 2010 Apache signed three Gas Plus contracts totaling 63 MMcf/d of gross production from fields in the Neuquén and Rio Negro Provinces. The first contract, for 10 MMcf/d at $4.10 per MMBtu for 2010, has been extended through 2011 for 11 MMcf/d at the $4.10 per MMBtu. The other two contracts, which together totaled 53 MMcf/d at $5.00 per MMBtu, are expected to commence in the first quarter of 2011. The gas supply is required to come from wells drilled in the projects approved fields and formations. We believe this program, reflects changing market conditions, which point to improving markets and price realizations going forward.
>
> Government-regulated pricing: The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. During 2010 we realized an average price of $1.20 per Mcf on government-regulated sales.

Unregulated market: The majority of our remaining volumes are sold into the unregulated market. In 2010 realizations averaged $2.65 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, 2010 oil prices realized from Tierra del

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Fuego oil production averaged $65.03 per barrel as compared to our Neuquén basin production, which averaged $53.68 per barrel.

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. This acreage is adjacent to our 552,000 net acres on the Argentine side of the island of Tierra del Fuego and represents a natural extension of our expanding exploration and production operations. The Lenga and Rusfin Blocks were ratified by the Chilean government on July 24, 2008. In January 2009 a 3-D seismic survey totaling 1,000 square kilometers was completed, and in November 2009 the first of a three-well exploration program commenced drilling. The three wells have now been drilled, and we are currently evaluating results.

Major Customers

In 2010 purchases by Shell accounted for 15 percent of the Company s worldwide oil and gas production revenues.

Drilling Statistics

Worldwide in 2010 we participated in drilling 904 gross wells, with 826 (91 percent) completed as producers. We also performed nearly 2,500 workovers and recompletions during the year. 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: 51 in the U.S. (25.04 net); 7 in Canada (6.18 net); 22 in Egypt (20 net); 2 in Australia (0.64 net); 3 in the North Sea (2.91 net); and 7 in Argentina (5.15 net).

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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
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
2008									
United States	4.5	6.6	11.1	334.8	25.3	360.1	339.3	31.9	371.2
Canada	3.9	5.0	8.9	328.0	10.1	338.1	331.9	15.1	347.0
Egypt	18.7	11.5	30.2	193.2	5.8	199.0	211.9	17.3	229.2
Australia	6.4	9.0	15.4	12.5		12.5	18.9	9.0	27.9
North Sea				11.7		11.7	11.7		11.7
Argentina	7.5	2.0	9.5	54.4	6.2	60.6	61.9	8.2	70.1
Total	41.0	34.1	75.1	934.6	47.4	982.0	975.6	81.5	1,057.1

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, 2010, is set forth below:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	5,165	3,040	2,370	7,995	17,535	11,035

Canada	10,100	8,405	2,500	1,100	12,600	9,505
Egypt	52	51	722	694	774	745
Australia	22	9	20	12	42	21
North Sea			77	75	77	75
Argentina	425	390	520	445	945	835
Total	15,764	11,895	16,209	10,321	31,973	22,216

Gross natural gas and crude oil wells include 1,600 wells with multiple completions.

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Production, Pricing and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGLs and gas production, 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:

Year Ended December 31,	Production Oil (MMbbls)	Production NGLs (MMbbls)	Production Gas (Bcf)	Average Lease Operatinge Cost per Boe	Average Sales Price Oil (Per bbl)	Average Sales Price NGLs (Per bbl)	Average Sales Price Gas (Per Mcf)
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
2008							
United States	32.9	2.2	248.8	$ 12.62	$ 83.70	$ 58.62	$ 8.86
Canada	6.3	0.7	129.1	14.00	93.53	49.33	7.94
Egypt	24.4		96.5	6.47	91.37		5.25
Australia	3.0		45.0	9.85	91.78		2.10
North Sea	21.8		1.0	10.00	95.76		18.78
Argentina	4.5	1.1	71.6	6.58	49.46	37.83	1.61
Total	92.9	4.0	592.0	10.56	87.80	51.38	6.70

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	4,809,425	2,846,337	4,955,265	2,848,363
Canada	3,834,513	2,960,531	4,527,542	3,334,602
Egypt	9,572,015	6,192,027	1,741,102	1,624,780
Australia	11,456,850	6,587,180	744,900	402,500
North Sea	780,811	406,157	41,019	39,846
Argentina	3,149,882	2,701,182	220,840	188,226
Chile	1,205,403	1,036,626		
Total	34,808,899	22,730,730	12,230,668	8,438,317

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As of December 31, 2010, we had 3,284,814, 1,588,390, and 3,552,045 net acres scheduled to expire by December 31, 2011, 2012, and 2013, 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, 2010, 30 percent of U.S. net undeveloped acreage and 36 percent of Canadian undeveloped acreage was held by production.

Estimated Proved Reserves and Future Net Cash Flows

Effective December 31, 2009, Apache adopted revised oil and gas disclosure requirements set forth by the SEC in Release No. 33-8995, Modernization of Oil and Gas Reporting and as codified by the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Topic 932, Extractive Industries Oil and Gas. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGL s 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. 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. Reserve estimates are considered proved if they are economically producible and are supported by either actual production or conclusive formation tests. 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 which 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. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

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.

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The following table shows proved oil, NGL and gas reserves as of December 31, 2010, based on average commodity prices in effect on the first day of each month in 2010, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. The 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	423	92	2,284	895
Canada	90	24	2,182	478
Egypt	110		748	234
Australia	48		683	162
North Sea	116		4	116
Argentina	16	6	462	100
Proved Undeveloped:				
United States	214	30	989	409
Canada	57	4	1,310	280
Egypt	17		329	72
Australia	18		805	152
North Sea	39			39
Argentina	4	1	71	16
TOTAL PROVED	1,152	157	9,867	2,953

As of December 31, 2010, Apache had total estimated proved reserves of 1,309 MMbbls of crude oil, condensate and NGLs and 9.9 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 3.0 billion barrels of oil or 17.7 Tcf of natural gas, of which oil represents 39 percent. As of December 31, 2010, the Company s proved developed reserves totaled 1,985 MMboe and estimated PUD reserves totaled 968 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 proved undeveloped reserves as of December 31, 2010, 2009, 2008 and 2007, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 12 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, 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 month in 2010 and 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. Future net cash flows as of December 31, 2008, were estimated using commodity prices in effect at the end of that year, in accordance with the SEC guidelines in effect prior to the issuance of the Modernization Rules.

Proved Undeveloped Reserves

The Company s total estimated PUD reserves of 968 MMboe as of December 31, 2010, increased by 237 MMboe over the 731 MMboe of PUD reserves estimated at the end of 2009. This increase was, in part, due to our 2010 acquisitions described above. During the year, Apache converted 64 MMboe of PUD reserves to proved developed reserves through development drilling activity. In North America we converted 31 MMboe, with the remaining 33 MMboe in our international areas.

During the year a total of approximately $1.1 billion was spent on projects associated with reserves that were carried as PUD reserves at the end of 2009. 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 $517 million on PUD reserve development activity in North America and $574 million in the international areas. At year-end 2010, no material amounts of PUD reserves remain undeveloped for five years or more after they were initially disclosed as PUD reserves.

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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.

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 2010 the properties selected for each country ranged from 63 to 100 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 85 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 63 percent of total proved reserves; 72 percent of proved developed reserves and 45 percent of proved undeveloped reserves. Properties with proved undeveloped 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 of proved developed reserves selected for review.

During 2010, 2009, and 2008, Ryder Scott s review covered 72, 79 and 82 percent of the Company s worldwide estimated proved reserves value and 63, 69, and 73 percent of the Company s total proved reserves, respectively. 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 United Kingdom 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 United Kingdom s total proved reserves. Ryder Scott s review of 2008 covered 70 percent of U.S., 51 percent of Canada, 58 percent of Argentina, 100 percent of Australia, 87 percent of Egypt and 89 percent of the United Kingdom 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.

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Employees

On December 31, 2010, we had 4,449 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 2010 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, 2013. For information regarding the Company s obligations under its office leases, please see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Contractual Obligations and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Title to Interests

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

Additional Information about Apache

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

Remediation Plans and Procedures

Apache adopted a Region Spill Response Plan (the Plan) for its Gulf of Mexico operations to ensure a rapid and effective response to spill events that may occur on Apache-operated properties. Periodically, drills are conducted to measure and maintain the effectiveness of the Plan. 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 in the event of a spill is CGA. Apache has received approval for the Plan from the BOEMRE. Apache personnel review the Plan annually and update where necessary.

Apache is a member of, and 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 2010 we paid CGA approximately $312,000: $12,800 per capita 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, resources of other organizations are available to Apache as a non-member, such as those of MSRC and National Response Corporation (NRC), 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 240 skimming systems, six 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 and dispersant aircraft. MSRC has contracts in place with many 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 work boats, 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.

Apache 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. In 2011, Apache s wholly-owned subsidiary Apache Deepwater LLC, retained the Helix Energy Solution Group in conjunction with its CGA membership, and will become a member of the Marine Well Containment Company to fulfill the government permit requirements for containment and oil spill response plans in Deepwater operations.

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. In November 2010 Apache entered into an agreed order with the Texas Commission on Environmental Quality and paid a total of $111,000 in administrative penalties to settle allegations regarding operations of two natural gas processing plants.

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.

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. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand.

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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 2010 ranged from a high of $92.89 per barrel to a low of $68.01 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2010 ranged from a high of $6.01 per MMBtu to a low of $3.29 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 or armed conflict) in crude oil or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil and natural gas;
- the price and availability of alternative fuels, including coal and biofuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- electricity generation;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

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

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

- a reduction in the carrying value of our crude oil and natural gas properties; or
- a reduction in the carrying value of goodwill.

We recorded asset impairment charges during 2008 and 2009. No impairment charges were recorded during 2010. If commodity prices decline, there could be additional impairments of our oil and gas assets or other investments or an impairment 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 flow.

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, 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;
- 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 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 flow 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 recent 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, as a result of the current lack of drilling activity in the deepwater Gulf of Mexico and slowdown of drilling activity on the Gulf of Mexico shelf caused by the regulatory response to the Deepwater Horizon incident, drilling equipment and oil field services companies may decide to exit the Gulf of Mexico, making such services less available and/or more expensive once drilling activities are allowed to fully resume.

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Any 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.

As has been widely reported, on April 20, 2010, a fire and explosion occurred onboard the semisubmersible drilling rig Deepwater Horizon, which lead to a significant oil spill that affected the Gulf of Mexico. In response to this incident, the BOEMRE ceased issuing drilling permits pursuant to a series of moratoria, and all deepwater drilling activities in progress were suspended. Although the moratoria have been lifted, the DOI has not issued any permits related to the drilling of new exploratory wells in the deepwater Gulf of Mexico as of January 31, 2011. In 2010 the DOI issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to regulate drilling activities and increase liability.

In January 2011 the President s National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps. The European Commission has recommended that new legislation be enacted to enhance the safety of offshore oil and gas activities. Additional legislation or regulation is being discussed which could require companies operating in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility, a certificate required by the Oil Pollution Act of 1990 which evidences a company s financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual insurance fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

The BOEMRE is expected to continue to issue new safety and environmental guidelines or regulations for drilling in the Gulf of Mexico, and other regulatory agencies could potentially issue new safety and environmental guidelines or regulations in other geographic regions, and may take other steps that could increase the costs of exploration and production, reduce the area of operations and result in permitting delays. We are monitoring legislation and regulatory developments; however, it is difficult to predict the ultimate impact of any new guidelines, regulations or legislation. A prolonged suspension of drilling activity in the U.S. and abroad and new regulations 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

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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.

During 2010 credit markets recovered but remain vulnerable to unpredictable shocks. We have a significant development project inventory and an extensive exploration portfolio, which will require substantial future investment. We and/or our partners may need to seek financing in order to fund these or other future activities. Our future access to capital, as well as that of our partners and contractors, could be limited if the debt or equity markets are constrained. This could significantly delay development of our property interests.

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

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

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

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

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

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

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

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions; and
- increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

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

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

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

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

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

The Mariner and BP transactions have exposed us to additional risks and uncertainties with respect to the acquired businesses and their operations.

Although the acquired Mariner and BP businesses are generally subject to risks similar to those to which we are subject in our existing businesses, the Mariner and BP transactions may increase these risks. For example, the increase in the scale of our operations may increase our operational risks. The publicity associated with the oil spill in the Gulf of Mexico resulting from the fire and explosion onboard the Deepwater Horizon, which was under contract to BP, may cause regulatory agencies to scrutinize our operations more closely. This additional scrutiny may adversely affect our operations.

We may have difficulty combining the operations of both Mariner and the BP properties, and the anticipated benefits of these transactions may not be achieved.

Achieving the anticipated benefits of the Mariner and BP transactions will depend in part upon whether we can successfully integrate the operations of Mariner and the BP properties with ours. Our ability to integrate the operations of Mariner and the BP properties successfully will depend on our ability to monitor operations, coordinate exploration and development activities, control costs, attract, retain and assimilate qualified personnel and maintain compliance with regulatory requirements. The difficulties of integrating the operations of Mariner and the BP properties may be increased by the necessity of combining organizations with distinct cultures and widely dispersed operations. The integration of operations following these transactions will require the dedication of management and other personnel, which may distract their attention from the day-to-day business of the combined enterprise and prevent us from realizing benefits from other opportunities. Completing the integration process may be more expensive than anticipated, and we cannot assure you that we will be able to effect the integration of these operations smoothly or efficiently or that the anticipated benefits of the transactions will be achieved.

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 have been reserved for after closing. We did not have sufficient time before closing on the BP Properties to conduct a full title review and environmental assessment. Although remedies are limited for title, 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, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. In accordance with the SEC s revisions to rules for oil and gas reserves reporting, which we adopted effective December 31, 2009, 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. The estimates 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 assumed effects of regulations by governmental agencies, including the impact of the SEC s new oil and gas company reserves reporting requirements;
- future operating costs;
- severance and excise taxes;
- development costs; 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 based on risk of recovery 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.

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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.

Legislation is pending in a number of countries where Apache operates including Australia, and Canada, the United Kingdom, that, if enacted, could tax or assess some form of greenhouse gas (GHG) related fees on Company operations and could lead to increased operating expenses. Such legislation, if enacted, could also potentially cause the Company to make significant capital investments for infrastructure modifications. Through 2011, three of the jurisdictions in which the Company has operations, Alberta and British Columbia, Canada and the United Kingdom (European Union), have enacted legislation which exposes the Company to financial payments related to GHG emissions from production facilities. This exposure has not been material to date.

Furthermore, various governmental entities in countries where Apache operates have discussed regulatory initiatives that could, if adopted, require the Company to modify existing or planned infrastructure to meet GHG emissions performance standards and necessitate significant capital expenditures. At some level, the cost of performance standards may force the early retirement of smaller production facilities, which in aggregate may have a material adverse effect on Apache s business.

Several of the countries we operate in are signatories to current international accords related to climate change, such as the Kyoto Protocol to the United Nations Framework Convention on Climate Change. Given the current implementation of the Kyoto Protocol, we do not expect it to have a material impact on the Company.

Several indirect consequences of regulation and business trends have potential to impact us. Taxes or fees on carbon emissions could lead to decreased demand for fossil fuels. Consumers may prefer alternative products and unknown technological innovations may make oil and gas less significant energy sources.

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 2012 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 14, 2011, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2012. 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

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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 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 the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. 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 well-bore. 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 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 2010 our operations in Egypt contributed 28 percent of our production revenue, 25 percent of total production and 10 percent of total estimated proved reserves. In 2010 we sold all of our Egyptian gas production and 34 percent of our Egyptian oil production to the Egyptian General Petroleum Company (EGPC), the Egyptian state-owned oil company, and sold the remainder in the export market. As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience that began on January 25, 2011, in the Egyptian capital of Cairo, former Egyptian president Hosni Mubarak has stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces is now in power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and that the military would rule for six months until elections can be held. Further changes 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.

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 52 percent of our 2010 production was outside North America and approximately 30 percent of our estimated proved oil and gas reserves on December 31, 2010 were located outside North America. As a result, a significant portion of our production and resources are subject to the increased political and economic risks and other factors associated with international operations including, but not limited to:

- general strikes and civil unrest;

- the risk of war, acts of terrorism, expropriation and resource nationalization, forced renegotiation or modification of existing contracts;

- import and export regulations;

taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;

price control;

transportation regulations and tariffs;

constrained natural gas markets dependent on demand in a single or limited geographical area;

exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;

laws and policies of the United States affecting foreign trade, including trade sanctions;

the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;

the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the United States; and

difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

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

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

In recent weeks civil unrest, which started in Tunisia, has spread to the Middle East. Prolonged and/or widespread regional conflict in the Middle East could have the following results, among others:

volatility in the 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, oil field 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, are affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect our results of operation, 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 result of operations.

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

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

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

ITEM 1B. *UNRESOLVED SEC STAFF COMMENTS*

As of December 31, 2010, 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. *[REMOVED AND RESERVED]*

PART II

ITEM 5. *MARKET FOR THE REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

During 2010 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 2010 and 2009. 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.

	2010				2009			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 108.92	$ 95.15	$ .15	$ .15	$ 88.07	$ 51.03	$ .15	$ .15
Second Quarter	111.00	83.55	.15	.15	87.04	61.60	.15	.15
Third Quarter	99.09	81.94	.15	.15	95.77	65.02	.15	.15
Fourth Quarter	120.80	96.51	.15	.15	106.46	88.06	.15	.15

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2011 (last trading day of the month), was $119.36 per share. As of January 31, 2011, there were 382,752,217 shares of our common stock outstanding held by approximately 5,700 stockholders of record and approximately 440,000 beneficial owners.

We have paid cash dividends on our common stock for 46 consecutive years through December 31, 2010. 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 7 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 2010 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, 2005, through December 31, 2010.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Apache Corporation, S&P 500 Index
and the Dow Jones US Exploration & Production Index

	2005	2006	2007	2008	2009	2010
Apache Corporation	$ 100.00	$ 97.70	$ 159.16	$ 111.05	$ 154.93	$ 180.12
S & P s Composite 500 Stock Index	100.00	115.79	122.16	76.96	97.33	111.99
DJ US Expl& Prod Index	100.00	105.37	151.39	90.65	127.42	148.14

* $100 invested on 12/31/05 in stock including reinvestment of dividends.
Fiscal year ending December 31.

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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, 2010, 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,				
	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Income Statement Data					
Total revenues	$ 12,092	$ 8,615	$ 12,390	$ 9,999	$ 8,309
Income (loss) attributable to common stock	3,000	(292)	706	2,807	2,547
Net income (loss) per common share:					
Basic	8.53	(.87)	2.11	8.45	7.72
Diluted	8.46	(.87)	2.09	8.39	7.64
Cash dividends declared per common share	.60	.60	.70	.60	.50
Balance Sheet Data					
Total assets	$ 43,425	$ 28,186	$ 29,186	$ 28,635	$ 24,308
Long-term debt	8,095	4,950	4,809	4,012	2,020
Shareholders equity	24,377	15,779	16,509	15,378	13,191
Common shares outstanding	382	336	335	333	331

For a discussion of significant acquisitions and divestitures, see Note 2 Significant 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 seven countries: the U.S., Egypt, Australia, offshore the U.K. in the North Sea (North Sea), Argentina and Chile.

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, with the following core strategic components:

- balanced portfolio of core assets;
- conservative capital structure; and
- 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. Our portfolio of geographic locations provides variation of all of these factors and, additionally, in the case of Australia and Argentina, the potential for increasing the value of our investments through rising natural gas prices. By maintaining a balanced hydrocarbon mix, we are protecting against price deterioration in a given product while retaining upside potential through a significant increase in either commodity price. For example, in 2010 oil and liquids provided 52 percent of our production but 77 percent of our total oil and gas revenues. We were well positioned to realize the benefit of higher oil prices, enabling record financial results despite North America natural gas prices that were under pressure most of the year.

Each operating region 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 core areas relative to product prices and, when appropriate, adjust our budgets accordingly. We review capital allocations, at least quarterly, through a disciplined and focused process of reviewing internally-generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects or, occasionally, new core areas which 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 2010 return on average capital employed and return on equity of 12 percent and 15 percent, respectively.

Preserving financial flexibility is also important to our overall business philosophy. We ended 2010 with a year-end debt-to-capitalization ratio of 25 percent, an increase of only one percent from the prior year despite current-year capital investments of $17 billion, including acquisitions totaling more than $11 billion.

Throughout the cycles of our industry, these strategic principles have underpinned our ability to deliver production, reserve growth and competitive investment rates of return 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.

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Financial and Operating Results

While Apache has grown into a much larger company than it was a year ago, we have stayed true to our business model, focusing on rate of return and cash-generating assets. Although the year 2010 will be remembered for the level of acquisition activity, the record financial results reflected continued growth and positive returns. For the 12-month period ending December 31, 2010, 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 658,000 boe/d, up 13 percent compared with 2009. Production in fourth-quarter 2010 averaged 729,000 boe/d, an increase of 24 percent from the 590,000 boe/d averaged in the fourth quarter of 2009.

Oil and gas production revenues for 2010 increased 42 percent to $12.1 billion, up from $8.6 billion in 2009, and just shy of the record $12.3 billion in 2008 when prices reached record levels.

Apache reported a record $3 billion in net income, or $8.46 per common diluted share, compared to a net loss of $292 million, or $.87 per share in the 2009 period. Apache s 2009 results were impacted by a $1.98 billion after-tax write-down of the carrying value of proved property. Apaches 2010 reported adjusted earnings(1), which exclude certain items impacting the comparability of results, were approximately $3.17 billion or $8.94 per common diluted share, up from $1.89 billion or $5.59 per common diluted share in the prior year.

Net cash provided by operating activities (operating cash flows or cash flows) totaled $6.7 billion, up 60 percent from $4.2 billion in 2009.

Estimated proved reserves at year-end 2010 were a record 2,953 MMboe, up 25 percent from 2009 estimated proved reserves of 2,367 MMboe.

(1) See *Non-GAAP Measures Adjusted Earnings* for a description of Adjusted Earnings, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and a reconciliation to this measure from Income (Loss) Attributable to Common Stock, which is presented in accordance with GAAP.

2011 Outlook

As we head into 2011, we project Apache s financial position will remain strong, given our debt-to-capitalization ratio of 25 percent, $2.4 billion of available committed borrowing capacity, projections of higher cash flows than 2010 levels and determination to hold exploration and development spending within our internally-generated cash flows. Given the present price disparity between oil and natural gas, our near-term focus is exploiting the oily and more liquids-rich properties in our portfolio and development of our gas resources in Australia and Canada, which we plan to convert to LNG and sell in the worldwide LNG market. As is the Apache way, rates of return will drive our decision making while we continue our focus on costs, operational efficiency and integrating the acquired assets. In 2011 we find ourselves with more opportunities than we can fund through internally-generated cash flow, and our challenge will be to optimize capital spending across our worldwide portfolio.

Our current 2011 capital budget includes exploration and development capital of approximately $7.5 billion. Nearly $4.0 billion is expected to be spent on projects in North America, with the remaining amount allocated across our international regions. An estimated one-third of our global capital budget is allocated to seismic and leasehold, GTP facilities and plugging and abandonment activities. While funds have been committed for certain 2011 exploration drilling, long-lead development projects and 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 other numerous industry factors and will adjust our exploration and development budgets based on changes to predicted operating cash flow. We typically review and revise our exploration and development capital budgets on a quarterly basis.

Based on the current capital spending budget and the acquisitions completed during 2010, Apache expects to increase overall production in 2011 between 13 percent and 17 percent from full-year 2010 production levels. These projections exclude the impact from any potential acquisitions or divestitures.

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The Company is currently planning to divest approximately $1.0 billion of properties to optimize and high-grade our existing portfolio of assets. The divestiture package will most likely include legacy conventional properties in Canada. However, as of the date of this filing we have not entered into any binding contracts to sell these assets. 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

Current Year

During 2010 we completed more than $11 billion of acquisitions, continued progress on developing existing core properties and expanded into new geographic areas. Through these steps, we added significantly to drilling inventory in our core areas and established a footprint in two new areas: deepwater exploration and LNG, which for us means the monetization of large gas resources at oil-linked prices.

Merger and Acquisitions of Property and Acreage

From 2007 to 2009 we were relatively absent from the acquisition market. We believed the market was overheated as oil and gas prices spiked, and the opportunities we identified did not meet our criteria for risk, reward and/or growth potential. We built our cash position while drilling our existing inventory of prospects and waiting for the right transactions to supplement it.

In June we completed the $1.05 billion acquisition of Devon Energy Corporation s oil and gas assets on the Gulf of Mexico (GOM) shelf, 75 percent of which are in fields now operated by Apache. The acquired assets include 477,000 net acres across 150 blocks. The Company believes that these well-maintained, high-quality assets fit well with Apache s existing infrastructure and play to the strengths that come with our experience operating on the shelf, exploiting the current production base and capturing upside potential.

In August we completed the $2.5 billion acquisition of oil and gas operations, acreage and infrastructure in the Permian Basin from BP plc (BP), solidifying our position as one of the most active operators in the area, where Apache has been competing for 20 years. The acquisition more than doubled our footprint in the Permian Basin to over three million gross acres.

In October we completed the $3.25 billion acquisition of substantially all of BP s upstream natural gas business in western Alberta and British Columbia, including 1.3 million net mineral and leasehold acres with significant positions in several emerging unconventional plays, such as the Noel tight-gas project, which ramped up to 100 MMcf/d by the end of the fourth quarter. We own a 100-percent working interest in the Noel project.

In November we closed on the purchase of BP assets in Egypt s Western Desert for $650 million, acquiring four development leases and one exploration concession as well as strategically-positioned infrastructure that will enable Apache to increase production from existing fields in the Western Desert.

Also in November, shareholders of Mariner Energy, Inc. (Mariner) approved the purchase of their company by Apache for stock and cash consideration totaling $2.7 billion. We also assumed approximately $1.7 billion of Mariner s debt with the merger. Apache established a strategic presence in the deepwater Gulf of Mexico and expanded our positions in the GOM shelf, Gulf Coast and Permian Basin with the acquisition. The acquisition also provides deepwater geoscience expertise, including a core competency in subsea tieback developments, which can significantly reduce the cycle time between exploration success and initial production.

During the first quarter of 2010 Apache Canada Ltd. (Apache Canada), through its subsidiaries, closed the acquisition of a 51-percent interest in a planned LNG export terminal (Kitimat LNG facility) and a 25.5-percent interest in a partnership that owns a related proposed pipeline. EOG Resources Canada, Inc. (EOG

Canada) owns the remaining 49 percent of the Kitimat LNG facility and a 24.5-percent interest in the pipeline partnership. In February 2011 Apache Canada and EOG Canada entered into an agreement to purchase the remaining 50-percent interest in the partnership. Upon close of the transaction, Apache Canada and EOG Canada will own 51 percent and 49 percent, respectively, of the pipeline partnership and proposed pipeline.

In Australia, during 2010 we expanded our exploration opportunities in the Carnarvon and Exmouth basins via farm-ins to seven permits. The transactions resulted in a 58-percent increase in our net undeveloped acreage in the Carnarvon basin and added 1.9 million acres for exploration in the Exmouth basin. We will operate all of them with a 20- to 70-percent working interest.

In the North Sea, we expanded our acreage position during the year through successful bids on four exploration licenses and farming into two additional licenses with a 50-percent working interest.

Egypt 2X Gross Production Achievement

Apache s Egypt operations had another year of growth in 2010, with gross daily production rising 16 percent to 322.5 Mboe/d and net daily production rising six percent to an average of 161.7 Mboe/d for the year. During the year the Company surpassed its late-2005 goal of doubling its Western Desert production within five years. Achievement of the goal was driven in part by production from several discoveries in the Faghur and Matruh basins, infrastructure improvements including two new Salam gas trains, expansion of the capacity of the Kalabsha oil processing and transportation facilities to 40,000 b/d and completion of a major strategic compression project on Egypt s northern gas pipeline. The Faghur and Matruh basins, where the thickness of the sands and the stacked pay zones present multiple opportunities for further exploration across our acreage, will continue to be focus areas for Apache in 2011.

Van Gogh and Pyrenees Oil Fields Development

Australia s 2010 production averaged a record 79.2 Mboe/d, driven by the Apache-operated Van Gogh oil field and BHP Billiton-operated Pyrenees oil field, both of which commenced production early in 2010. The Van Gogh and Pyrenees developments utilize Floating Production Storage and Offloading (FPSO) vessels and together added 42.2 Mb/d to Apache s 2010 net oil production. Both projects have already reached payout.

Organic Growth Drivers 2011 to 2013

Australia Reindeer Field Development and Devil Creek Gas Plant

Our Reindeer field discovery is projected to commence production in 2011 upon completion of the Devil Creek Gas Plant. The Devil Creek Gas Plant is scheduled to be commissioned in the fourth quarter of 2011. This will be Western Australia s first new domestic natural gas processing hub in more than 15 years. The two-train plant is designed to process 200 MMcf/d from the Apache-operated Reindeer Field. In 2009 we entered into a gas sales contract covering a portion of the field s future production. Under the contract, Apache and our joint venture partner agreed to supply 154 Bcf of gas over seven years (approximately 60 MMcf/d) beginning in the fourth quarter of 2011 at prices substantially higher than we have historically received in Western Australia. Apache owns a 55-percent interest in the field.

Australia Halyard Field Development

Initial production from our Halyard-1 discovery well in Australia is projected for 2011 upon completion of the tie-in to the existing gas facilities on Varanus Island. The extension of this subsea infrastructure will also connect the 2010

Spar-2 discovery and allow for tie-in of future wells.

North Sea Satellite Platform

In November Apache entered into a contract to build a new satellite oil production platform for our UK Forties field. The new platform will be bridge-linked to our existing Forties Alpha installation in the Apache-operated field, located on the U.K. continental shelf. This project 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. Construction is projected to be complete by mid-year 2012.

Australia Macedon Field Development

The Macedon gas field s four development wells, which were completed in 2010, will be delivered via a 60-mile pipeline to a 200 MMcf/d gas plant to be built at Ashburton North in Western Australia. We have a 28-percent non-operated working interest in the field. The project, approved in 2010, is currently underway, with first production projected in 2013.

Australia Coniston Oil Field Discovery

The Coniston field is an oil accumulation near our Van Gogh field in Australia. Apache drilled 10 appraisal wells during 2009, and current plans call for subsea completions tied back to the Van Gogh field FPSO Ningaloo Vision. The project has been sanctioned for development, with first production into the domestic market projected in 2013.

North America Unconventional Gas Plays

The identification and development of significant resources in shale formations and other unconventional gas plays have introduced substantial gas supplies into North American natural gas markets for the foreseeable future. Although Apache s current production in North America is primarily conventional, near-term gas production growth 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 Granite Wash tight sands in the Anadarko basin of Oklahoma and the Texas Panhandle.

Horizontal Drilling and Completion Techniques

Apache continues to evaluate horizontal drilling potential across our acreage positions around the world, in both conventional and unconventional reservoirs. In the Permian Basin, Apache is utilizing horizontal drilling to access bypassed, unswept zones in established waterfloods. We are currently drilling our first horizontal shale well in Argentina, targeted for completion in April. In addition, we plan to drill our first horizontal well in the Western Desert of Egypt in 2011. The Company will continue to evaluate our opportunities utilizing horizontal drilling technology.

Organic Growth Drivers 2014 and Beyond

Australia Balnaves Oil Field Discovery Development

In October 2010 we announced three successful wells appraising our Balnaves-1 discovery, an oil accumulation in a separate reservoir beneath the large gas reservoirs of our Brunello gas fields (discussed below). The project is currently in the FEED stage, with plans to develop the field through a new FPSO. First production, if the decision is made to go forward with the project, is projected for 2014.

Julimar and Brunello Field Discoveries Development/Wheatstone LNG Project

In 2016, we are projecting to begin production from our operated Julimar and Brunello field gas discoveries through the Chevron operated Wheatstone LNG hub, in which we own a foundation equity partner interest of 13 percent. Apache s projected net gas sales from the fields are 160 MMcf/d and 3,250 b/d with a projected 15-year production plateau when the multi-year project is fully operational. The Wheatstone project, which is currently in FEED, will convert the gas into LNG for sale on the world market. World LNG prices are typically oil-linked prices and are currently higher than the historical gas prices in Western Australia. The project Final Investment Decision (FID) is scheduled for 2011, with first LNG projected in 2016. Nonbinding Heads of Agreements have been signed with LNG buyers and final binding sales and purchase agreements will be completed by FID.

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Kitimat/Horn River Basin Development

Apache s time horizon and magnitude of our Horn River basin shale gas development is impacted by North American gas prices and the completion of 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, including the Horn River basin area in northeast British Columbia. Apache Canada and EOG Canada 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 five million metric tons of LNG per year, of which Apache Canada has reserved 51 percent. The proposed 287-mile pipeline 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. Apache Canada will have rights to 51-percent of the capacity in the proposed pipeline. Completion of the FEED study and a final investment decision are targeted for late 2011. Construction is expected to commence in 2012, with commercial operations projected to begin in 2015.

GOM Deepwater

Apache has built deepwater experience and a record of success in Egypt, Australia and the Gulf of Mexico, on both the exploration and development sides. The GOM deepwater portfolio gained in the Mariner merger adds over 100 blocks and offers a strategic position into a significant potential growth area in the United States that can add meaningful oil reserves and production over the long term. Exploration potential is generated from Mariner s extensive track record of 36 deepwater development projects completed to date and the technological developments in seismic and facilities making exploration more predictable, lower risk and lower cost. Our pipeline of development projects include the non-operated Heidelberg (12.5-percent net working interest) and Lucius (16.67-percent net working interest) discoveries, which are still under further appraisal and study for ultimate development.

Significant Events

Impact of Deepwater Drilling Moratorium on Gulf of Mexico Operations

In 2010 the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) announced a series of moratoria, which directed oil and gas lessees and operators to cease drilling new deepwater (depths greater than 500 feet) wells on the Outer Continental Shelf (OCS), and put oil and gas lessees and operators on notice that, with certain exceptions, the BOEMRE would not consider drilling permits for deepwater wells and related activities. While the moratoria have been formally lifted, no new permits for deepwater drilling have been issued as of the date of this filing.

In addition, the BOEMRE issued new regulations in 2010 requiring additional information, documentation and analysis for all new wells on the OCS. The effect of these new regulations was to significantly slow down issuance of permits for shallow wells. Apache continues to operate under these new regulations and, through February 2011, has received 25 drilling permits for shallow wells. Current permitting activity has been slowed compared to prior-year levels, and the Company has budgeted its exploration and development activity accordingly.

Impact of Recent Political Changes on Egyptian Operations

In 2010 our operations in Egypt contributed 28 percent of our production revenue, 25 percent of total production and 10 percent of total estimated proved reserves. In 2010 we sold all of our Egyptian gas production and 34 percent of our Egyptian oil production to Egyptian General Petroleum Company (EGPC), the Egyptian state-owned oil company. The remainder of our oil was sold in the export market.

As a result of political unrest, protests, riots, street demonstrations and acts of civil disobedience that began on January 25, 2011, in the Egyptian capital of Cairo, Egyptian president Hosni Mubarak stepped down, effective February 11, 2011. The Egyptian Supreme Council of the Armed Forces assumed power. On February 13, 2011, the Council announced that the constitution would be suspended, both houses of parliament would be dissolved, and the military would rule for six months until elections can be held. Following the advice of the U.S. State Department, Apache evacuated all non-essential personnel from Egypt. As conditions stabilized, approximately one-third of the evacuated employees returned. Apache s production, located in remote locations in the Western Desert, has continued uninterrupted; however, further changes 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 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 covering losses arising from confiscation, nationalization, and expropriation risks and currency inconvertibility. In addition, the Company has a separate policy with OPIC, which provides $300 million of coverage for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum when actions taken by the Government of Egypt prevent Apache from exporting our share of production.

Operations Downtime

Production from our Van Gogh oil field was impacted by essential maintenance activities on the FPSO. Net fourth quarter production of 6,100 b/d was down 17,600 b/d from the previous quarter. Production resumed in the first half of February 2011.

In January 2011 a subsea pipeline connecting our Forties Bravo platform to our Charlie platform was shut-in because of corrosion. A project is underway to re-route the production through a smaller line until a new flexible pipeline is installed. This intermediate solution should be completed by the first of March 2011 and will allow us to produce approximately half of the 11,600 b/d that flowed through the main pipeline. The new main subsea pipeline will be completed by September 2011.

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Results of Operations

Oil and Gas Revenues

	For the Year Ended December 31,								
	2010			2009			2008		
	$ Value (In millions)		% Contribution	$ Value (In millions)		% Contribution	$ Value (In millions)		% Contribution
Oil Revenues:									
United States	$	2,683	30%	$	1,922	32%	$	2,751	34%
Canada		388	4%		311	5%		587	7%
North America		3,071	34%		2,233	37%		3,338	41%
Egypt		2,875	32%		2,063	34%		2,232	27%
Australia		1,296	14%		230	4%		277	3%
North Sea		1,590	18%		1,356	22%		2,085	26%
Argentina		209	2%		207	3%		225	3%
International		5,970	66%		3,856	63%		4,819	59%
Total(2)	$	9,041	100%	$	6,089	100%	$	8,157	100%
Natural Gas Revenues:									
United States	$	1,409	49%	$	1,054	44%	$	2,204	56%
Canada		647	23%		546	23%		1,026	26%
North America		2,056	72%		1,600	67%		3,230	82%
Egypt		495	17%		490	21%		507	13%
Australia		163	6%		133	6%		95	2%
North Sea		16	0%		13	0%		18	0%
Argentina		132	5%		133	6%		115	3%
International		806	28%		769	33%		735	18%
Total(3)	$	2,862	100%	$	2,369	100%	$	3,965	100%
Natural Gas Liquids (NGL) Revenues:									
United States	$	208	74%	$	74	64%	$	128	62%
Canada		39	14%		20	17%		38	19%
North America		247	88%		94	81%		166	81%

Egypt		2	1%			0%			0%
Argentina		31	11%		22	19%		40	19%
International		33	12%		22	19%		40	19%
Total	$	280	100%	$	116	100%	$	206	100%
Total Oil and Gas Revenues:									
United States	$	4,300	35%	$	3,050	36%	$	5,083	41%
Canada		1,074	9%		877	10%		1,651	14%
North America		5,374	44%		3,927	46%		6,734	55%
Egypt		3,372	28%		2,553	30%		2,739	22%
Australia		1,459	12%		363	4%		372	3%
North Sea		1,606	13%		1,369	16%		2,103	17%
Argentina		372	3%		362	4%		380	3%
International		6,809	56%		4,647	54%		5,594	45%
Total(1)	$	12,183	100%	$	8,574	100%	$	12,328	100%

(1) Financial derivative hedging activities increased oil and gas production revenues for 2010 and 2009 by $165.3 million and $180.8 million, respectively, and decreased oil and gas production revenues for 2008 by $458.7 million.

(2) Financial derivative hedging activities decreased 2010 oil revenues by $57.0 million, increased 2009 oil revenues by $45.2 million and decreased 2008 oil revenues by $450.8 million.

(3) Financial derivative hedging activities increased natural gas revenues for 2010 and 2009 by $222.3 million and $135.6 million, respectively, and decreased natural gas revenues for 2008 by $7.9 million.

Production

	For the Year Ended December 31,				
	2010	Increase (Decrease)	2009	Increase (Decrease)	2008
Oil Volume b/d:					
United States	96,576	+8%	89,133	−1%	89,797
Canada	14,581	−4%	15,186	−11%	17,154
North America	111,157	+7%	104,319	−2%	106,951
Egypt	99,122	+8%	92,139	+38%	66,753
Australia	45,908	+369%	9,779	+19%	8,249
North Sea	56,791	−7%	60,984	+3%	59,494
Argentina	9,956	−13%	11,505	−7%	12,409
International	211,777	+21%	174,407	+19%	146,905
Total(1)	322,934	+16%	278,726	+10%	253,856
Natural Gas Volume Mcf/d:					
United States	730,847	+10%	666,084	−2%	679,876
Canada	396,005	+10%	359,235	+2%	352,731
North America	1,126,852	+10%	1,025,319	−1%	1,032,607
Egypt	374,858	+3%	362,618	+38%	263,711
Australia	199,729	+9%	183,617	+49%	123,003
North Sea	2,391	−12%	2,703	+3%	2,637
Argentina	184,830	0%	184,557	−6%	195,651
International	761,808	+4%	733,495	+25%	585,002
Total(2)	1,888,660	+7%	1,758,814	+9%	1,617,609
NGL Volume b/d:					
United States	13,777	+125%	6,136	+3%	5,986
Canada	2,884	+38%	2,089	+1%	2,076
North America	16,661	+103%	8,225	+2%	8,062

Egypt	82	N/A		N/A	
Argentina	3,180	−2%	3,241	+12%	2,887
International	3,262	+1%	3,241	+12%	2,887
Total	19,923	+74%	11,466	+5%	10,949
BOE per day(3)					
United States	232,161	+13%	206,284	−1%	209,097
Canada	83,466	+8%	77,147	−1%	78,018
North America	315,627	+11%	283,431	−1%	287,115
Egypt	161,680	+6%	152,575	+38%	110,704
Australia	79,196	+96%	40,382	+40%	28,750
North Sea	57,190	−7%	61,435	+3%	59,934
Argentina	43,941	−3%	45,505	−5%	47,904
International	342,007	+14%	299,897	+21%	247,292
Total	657,634	+13%	583,328	+9%	534,407

(1) Approximately 12 percent of 2010 oil production was subject to financial derivative hedges, compared to 10 percent in 2009 and 19 percent in 2008.

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(2) Approximately 23 percent of 2010 gas production was subject to financial derivative hedges, compared to nine percent in 2009 and 20 percent in 2008.

(3) The 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.

Pricing

	For the Year Ended December 31,				
	2010	Increase (Decrease)	2009	Increase (Decrease)	2008
Average Oil price Per barrel:					
United States	$ 76.13	+29%	$ 59.06	–29%	$ 83.70
Canada	72.83	+30%	56.16	–40%	93.53
North America	75.69	+29%	58.64	–31%	85.28
Egypt	79.45	+30%	61.34	–33%	91.37
Australia	77.32	+20%	64.42	–30%	91.78
North Sea	76.66	+26%	60.91	–36%	95.76
Argentina	57.47	+16%	49.42	0%	49.46
International	77.21	+27%	60.58	–32%	89.63
Total(1)	76.69	+28%	59.85	–32%	87.80
Average Natural Gas price Per Mcf:					
United States	$ 5.28	+22%	$ 4.34	–51%	$ 8.86
Canada	4.48	+7%	4.17	–47%	7.94
North America	5.00	+17%	4.28	–50%	8.55
Egypt	3.62	–2%	3.70	–30%	5.25
Australia	2.24	+13%	1.99	–5%	2.10
North Sea	18.64	+42%	13.15	–30%	18.78
Argentina	1.96	0%	1.96	+22%	1.61
International	2.90	+1%	2.87	–16%	3.43
Total(2)	4.15	+12%	3.69	–45%	6.70
Average NGL Price Per barrel:					
United States	$ 41.45	+26%	$ 33.02	–44%	$ 58.62
Canada	36.61	+43%	25.54	–48%	49.33
North America	40.62	+31%	31.12	–45%	56.23
Egypt	69.75	N/A		N/A	
Argentina	27.08	+44%	18.76	–50%	37.83
International	28.15	+50%	18.76	–50%	37.83
Total	38.58	+40%	27.63	–46%	51.38

(1) Reflects per-barrel decrease of $.48 in 2010, an increase of $.44 in 2009 and a reduction of $4.85 in 2008 from financial derivative hedging activities.

(2) Reflects per-Mcf increase of $.32 in 2010 and $.21 in 2009 and a reduction of $.01 in 2008 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 2010 were 28 percent above 2009 with economies stabilizing or growing across the globe. Apache uses financial instruments to manage a portion of its exposure to fluctuations in crude oil prices, particularly in North America. In 2010, 12 percent of our oil production was subject to financial derivative hedges, reducing revenues by $57 million. In 2009, 10 percent of our oil production was hedged, increasing oil revenue by $45 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.

While the market price received for crude oil varies among geographic areas, 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 Australia, Apache continues to directly market all of our crude oil production into Australian domestic and international markets at prices indexed to Dated Brent benchmark crude oil prices plus a premium, which are typically above NYMEX oil prices. 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, but producers retain a value-added tax collected from buyers, effectively increasing price realizations by 21 percent.

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. 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 2010, 23 percent of our gas production was subject to financial derivative hedges, increasing revenues by $222 million. In 2009, nine percent of our gas production was hedged, increasing gas revenue by $136 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.

Apache primarily sells natural gas into the North American market, where spot prices increased 17 percent compared to 2009, and various international markets, where our average contracted prices rose just one percent from 2009. Our primary markets include North America, Egypt, Australia and Argentina.

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, with a majority under an industry pricing formula indexed to Dated Brent crude oil with a maximum gas price of $2.65 per MMBtu. On up to 100 MMcf/d of gross production, there is no price cap for our gas under a legacy contract, which expires at the end of 2012. Overall, the region averaged $3.62 per Mcf in 2010.

Australia has 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, including our Reindeer field, are substantially higher than historical levels.

In Argentina we receive government-regulated pricing on a substantial portion of our production. The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. During 2010 we realized an average price of $1.20 per Mcf on government-regulated sales. The majority of the remaining volumes were sold at market-driven prices, which averaged $2.65 per Mcf in 2010.

Our overall average realized price for 2010 was $1.96 per Mcf, the same as our 2009 average realized price and 22 percent higher than 2008 average realized price ($1.61 per Mcf).

During 2010 Apache signed three Gas Plus contracts totaling 63 MMcf/d of gross production from fields in the Neuquén and Rio Negro Provinces. Gas Plus is a program instituted by the Argentine government to encourage new gas supplies through the development of tight sands and unconventional reserves. The first contract, for 10 MMcf/d at $4.10 per MMBtu, has been extended through 2011 for 11 MMcf/d at $4.10 per

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MMbtu. Our other two Gas Plus contracts, for a total of 53 MMcf/d at $5.00 per MMBtu, are projected to commence in the first quarter of 2011. The gas supplying the Gas Plus program contracts is required to come from wells drilled in the projects approved fields and formations. We believe the Gas Plus program, coupled with changing market conditions, point to improving price realizations going forward.

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

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 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. Production in Argentina and Canada declined 1.5 Mb/d and .6 Mb/d, respectively, on natural decline.

2009 vs. 2008 Crude oil accounted for 48 percent of our equivalent production and 71 percent of oil and gas production revenues during 2009, compared to 48 and 66 percent, respectively, for 2008. Impacted by dramatically lower oil prices realized during the global financial crisis that began in late 2008, crude oil revenues for 2009 totaled $6.1 billion, $2.1 billion lower than the prior year. A 32-percent decline in average realized prices reduced revenues $2.6 billion, of which $528 million was offset by the impact of 10 percent production growth.

Worldwide production increased 24.9 Mb/d despite curtailed capital spending, which was 40 percent lower than 2008. Egypt s oil production increased 38 percent or 25.4 Mb/d on exploration successes in numerous concessions, most notably East Bahariya Extension, South Umbarka, Matruh, Northeast Abu Gharadig Extension and Khalda, waterflood projects and increased condensate from additional Qasr gas flowing through the new processing trains at the Salam Gas Plant. Australia s production was up 1.5 Mb/d, as production was restored following completion of repairs at Varanus Island. North Sea production increased 1.5 Mb/d on strong drilling results, which offset the impact of unplanned downtime at the Bravo Platform, which lowered 2009 average daily oil production by 2.6 Mb/d. The Bravo Platform was down for most of the fourth quarter for pipeline repairs. Production declined 2.0 Mb/d in Canada, .9 Mb/d in Argentina and .7 Mb/d in the U.S., as natural decline offset results from our curtailed 2009 drilling programs.

Natural Gas Revenues

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 and the $.46 per Mcf increase 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

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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. An active drilling and completion program at Horn River and additional volumes from properties acquired from BP led Canada region production 36.8 MMcf/d higher. 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.

2009 vs. 2008 Natural gas accounted for 50 percent of our equivalent production and 28 percent of our oil and gas production revenues during 2009, compared to 50 and 32 percent, respectively, for 2008. Impacted by dramatically lower gas prices realized during the global financial crisis that began in late 2008, gas revenues for 2009 totaled $2.4 billion, down $1.6 billion from 2008. A 45-percent decline in average realized prices reduced revenues $1.8 billion, partially offset by the $184 million impact of a nine percent increase in production.

Worldwide production grew 141 MMcf/d, driven by a 99 MMcf/d increase in Egypt s net production and a 61 MMcf/d increase in Australia. Egypt s gas production was up 38 percent on exploration successes at our Khalda and Matruh concessions and additional plant and pipeline capacity. Additional capacity provided by the combination of two new processing trains at the Salam Gas Plant and completion of a project to increase compression on the Northern Gas Pipeline allowed previously discovered wells in our Khalda Concession Qasr field to come online. Australia s 49 percent production increase was driven by production restorations following completion of repairs to the Varanus Island facility. Canada s gas production increased 6 MMcf/d from drilling and recompletion activities and a lower effective royalty rate, partially offset by natural decline. Argentine production decreased 11 MMcf/d on natural decline and lower capital spending levels. U.S. daily production declined 14 MMcf/d. Production in the Gulf Coast decreased 8 MMcf/d as production shut-in for facility, rig and third-party downtime repairs reduced the 2009 production by 30 MMcf/d, which more than offset net production gains from drilling results. Our Central region s production declined 6 MMcf/d primarily a result of the region s curtailed drilling program, which was deferred until service costs fell in line with lower commodity prices. Most of the regions drilling activity occurred in the second half of the year.

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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 relevance.

	Year Ended December 31,			Year Ended December 31,		
	2010	2009	2008	2010	2009	2008
		(In millions)			(Per boe)	
Depreciation, depletion and amortization:						
Oil and gas property and equipment						