APACHE CORP
Form 10-K
February 26, 2010

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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, 2009

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

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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule-405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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, 2009	$ 24,224,151,606
Number of shares of registrant s common stock outstanding as of January 31, 2010	336,550,234

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant s proxy statement relating to registrant s 2010 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.

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.

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

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PART I

ITEMS 1 AND 2. *BUSINESS AND PROPERTIES*

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. In North America, our exploration and production interests are focused in the Gulf of Mexico, the Gulf Coast, East Texas, the Permian Basin, the Anadarko Basin and the Western Sedimentary Basin of Canada. Outside of North America, we have exploration and production interests onshore Egypt, offshore Western Australia, offshore the U.K. in the North Sea (North Sea), and onshore Argentina. We also have exploration interests on the Chilean side of the island of Tierra del Fuego. 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 19, 2009, 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 United States (U.S.), Canadian and other international properties through subsidiaries, including Apache Canada Ltd., DEK Energy Company (DEKALB), Apache Energy Limited (AEL), Apache North America, Inc. and Apache Overseas, Inc. 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 upstream oil and gas company for the long-term benefit of our shareholders. Apache s long-term perspective has many dimensions, with the following core principles:

- own a balanced portfolio of core assets;
- maintain financial flexibility and a strong balance sheet; and
- optimize rates of return, earnings and cash flow.

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 24 years and production 29 out of the past 31 years, a testament to our consistency over the long-term.

Portfolio of Assets

We own a portfolio of assets in core areas that provide opportunities for growth through drilling, supplemented by occasional strategic acquisitions. Over the last two decades, we have assembled a large acreage position and

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production base outside the United States that provide additional geologic and geographic opportunities, diversifying risk, and provide exposure to larger reserve targets, which fuel production and reserve growth. We now have exploration and production operations in six countries, spanning five continents: the Gulf Coast and Central regions in the United States (U.S.), Canada, Egypt, the North Sea, Australia and Argentina. We also have exploration interests in Chile located adjacent to our Argentine operations on the Chilean side of the island of Tierra del Fuego.

Each of our producing regions has achieved an economy of scale that leads to cost effective production and sustainable, lower-risk, repeatable drilling opportunities. The net cash provided by operating activities (cash flow) generated by our current production base and our 33 million gross acres across the globe provide the ability to pursue new exploration targets while developing our previous exploration discoveries. Those developments will fund the next round of exploration activities and development programs.

We manage our investments giving consideration to geography, reserve life and hydrocarbon mix.

No single region contributed more than 27 percent of our equivalent production or reserves in 2009.

The mixture of reserve life (estimated reserves divided by annual production) in our regions, which translates into balance in the timing of returns on our investments, ranges from as short as six years to as long as 21 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 2009 crude oil and liquids provided 50 percent of our production and 72 percent of our revenue. At year-end, our estimated proved reserves were 45 percent crude oil and liquids and 55 percent natural gas.

Financial Flexibility and a Strong Balance Sheet

Apache s financial flexibility is the result of years of hard work and discipline. This flexibility permits us to pursue higher-risk, higher-reward exploration targets, to develop large-scale facilities required to produce previous exploration discoveries and, when appropriate, to supplement our drilling and exploration programs with value-creating acquisitions.

Given the turmoil in the commodity markets and nearly unprecedented global financial crisis at the outset of the year, Apache s primary objective for 2009 was to live within our cash flow and preserve our financial flexibility. To ensure we lived within cash flow, we reduced our 2009 activity and invested $4.1 billion, 39 percent below 2008 levels.

Apache grew production nine percent and generated $4.2 billion in cash flow in 2009 in spite of curtailed capital spending. We exited 2009 with a debt-to-capitalization ratio of 24 percent, just over $2 billion of cash and $2.3 billion in available committed borrowing capacity. We also believe our single-A debt ratings provide a competitive advantage in accessing capital markets.

Optimize Returns on Invested Capital

We focus on optimizing returns on invested capital through strict cost control and the creative application of technology.

Our management systems provide a uniform process of measuring success across Apache. Our management systems 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 monitor capital allocations, at least quarterly, through a disciplined and focused process that includes analyzing current economic conditions, expected rates of return on proposed development and exploration drilling targets, opportunities for tactical acquisitions or, occasionally, new core areas that could enhance our portfolio.

We also use technology to optimize our rates of return by reducing risk, decreasing drilling time and costs, and maximizing recoveries from reservoirs. Additionally, Apache scientists and engineers have been granted numerous

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patents for a range of inventions, from systems used for interpreting seismic data or processing well logs to improvements in drilling and completion techniques.

One such example is a manifold invented for development of 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 for a manifold that will connect all 16 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 increase Apache s rate of return on potentially thousands of future wells across our leasehold.

At our Forties field, 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 three-dimensional seismic surveys, is utilized by Apache to create a time-lapse picture that shows where oil remains after 35 years of production. The latest model of the reservoir highlighted the potential for stranded oil accumulations in close proximity to the Charlie platform and helped Apache s technical teams identify the Charlie 6-3 target drilled in 2009. The well came on production at 10,500 b/d the field s highest initial production rate from a new well since 1994.

For a more in-depth discussion of our 2009 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.

Geographic Area Overviews

We currently have exploration and production interests in six countries, divided into seven operating regions: the United States (Gulf Coast and Central regions), Canada, Egypt, Australia, offshore the United Kingdom in the North Sea and Argentina. We also have exploration interests on the Chilean side of the island of Tierra del Fuego, which we acquired in the second quarter of 2008.

The following table sets out a brief comparative summary of certain key 2009 data for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2009 Production (In MMboe)	**Percentage of Total 2009 Production**	**2009 Production Revenue (In millions)**	**12/31/09 Estimated Proved Reserves (In MMboe)**	**Percentage of Total Estimated Proved Reserves**	**2009 Gross New Wells Drilled**	**2009 Gross New Productive Wells Drilled**
Region/Country:							
Gulf Coast	42.8	20%	$ 1,814	300.0	13%	26	15
Central	32.5	15	1,236	630.0	27	135	133
Total U.S.	75.3	35	3,050	930.0	40	161	148
Canada	28.2	13	877	531.0	22	201	188
Total North America	103.5	48	3,927	1,461.0	62	362	336

Egypt	55.7	26	2,553	308.8	13	164	147
Australia	14.7	7	363	305.3	13	33	28
North Sea	22.4	11	1,369	172.5	7	17	14
Argentina	16.6	8	362	119.0	5	32	31
Other International						2	2
Total International	109.4	52	4,647	905.6	38	248	222
Total	212.9	100%	$ 8,574	2,366.6	100%	610	558

North America

Apache s North American asset base comprises the U.S. Central region, U.S. Gulf Coast region and our Canada region. Oil and liquids production, mainly from the U.S. Permian Basin and the Gulf of Mexico, made up

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nearly 40 percent of North America s 2009 barrel-equivalent production and 46 percent of North America s year-end estimated proved reserves. Our North American production is also balanced between the shorter reserve life but higher rates of return in the Gulf of Mexico and longer reserve life for Apache s onshore assets in Canada and the Permian and Anadarko Basins of the United States.

As result of past growth and future opportunities available in the Central region, we have created a new regional unit beginning in 2010. Our Permian region will be based in Midland, Texas and will be responsible for our Permian Basin business. The Central region will focus on our extensive holdings in Oklahoma, East Texas and the Texas Panhandle, especially the Granite Wash play.

The identification and commercialization of significant resources in shale formations and other unconventional gas plays has changed the natural gas markets for the foreseeable future, with current estimates that North America has a 100-year resource of natural gas. Although Apache s current production in North America is primarily conventional, near-term growth will likely be driven by activity in two large growth plays: shale gas in British Columbia s Horn River Basin and the Granite Wash tight sands in the Anadarko Basin of Oklahoma and the Texas Panhandle. Apache has identified many years of drilling activity in both plays.

We anticipate that the increased supply of natural gas will ultimately encourage producers to seek new and unconventional markets for their supply. Apache is one of the first independent producers to seek global markets for its North American natural gas production through our acquisition of a 51-percent ownership and throughput capacity interest in the proposed Kitimat LNG Terminal in British Columbia.

In order to live within expected cash flow, Apache curtailed exploration and development capital at the outset of 2009. In North America we drilled 362 gross wells, down from 1,015 wells in 2008. Exploration, drilling, and acquisition spending totaled $1.6 billion in 2009, 49 percent lower than in 2008. Despite lower activity and spending, we added 122.3 MMboe of estimated proved reserves through drilling and acquisitions in North America, 18.8 MMboe more than the 103.5 MMboe produced. Equivalent production from our North American regions declined one percent year-over-year.

We are ramping up activity in early 2010 as we move into development mode at Horn River, increase drilling in the Granite Wash formation and double our oil drilling activity in the Permian Basin. In 2010, we currently plan to drill or participate in 561 gross wells in North America.

United States

Overview In the U.S., the Gulf Coast region s assets, balanced between oil and natural gas, historically generate high rates of return on invested capital. Occasional acquisitions have played an important role, as steep decline rates mean offshore reserves are generally shorter-lived and difficult to replace on a cost-effective basis through drilling alone. The Central region brings the balance of long-lived reserves and consistent drilling results to the portfolio.

Gulf Coast Region This region comprises our interests in and along the Gulf of Mexico, in the areas on and offshore Louisiana and Texas. Apache has been the largest held-by-production acreage owner since 2004, and the second largest producer on the Outer Continental Shelf of the Gulf of Mexico (waters less than 1,200 feet deep). The region also holds 1.2 million gross acres along the Gulf Coast of Louisiana and Texas. In 2009 the region contributed approximately 20 percent of our worldwide production, about 21 percent of our revenues and, at year-end, held nearly 13 percent of our estimated proved reserves.

The region had a productive year despite the capital curtailment stemming from lower commodity prices at the end of 2008. The region drilled or participated in 26 wells, down from 116 wells in 2008, and performed 217 workovers and recompletions.

In May 2009 production commenced from two deepwater wells in the Geauxpher field, located on Garden Banks Block 462. During the second half of 2009, the field produced an average of 91 MMcf/d gross. Apache generated the prospect and has a 40-percent working interest. We also announced another key deepwater discovery in April 2009 at Ewing Banks 998 that test-flowed 4,254 b/d and 5.4 MMcf/d. The well will be connected to existing facilities, with first production projected for mid-year 2010. Apache owns a 50-percent interest in the property.

The risk of hurricanes in the Gulf Coast region has been an ongoing issue. Frequency, intensity and location of major hurricanes is impossible to predict. The majority of our Gulf of Mexico assets have enjoyed full-life cycles without suffering significant storm-related damage. While facilities are designed to withstand severe weather, they may incur significant damage when confronted by the most extreme hurricane conditions. Also, with mature facilities, proactive management includes aggressive well and equipment abandonment that should minimize the environmental impact and reduce the eventual cost of remediation.

This damage may result in expenses for repairs to restore production as well as expenses to remove and abandon wreckage. During 2009, approximately $64 million in excess of insurance proceeds was spent to repair damage stemming from 2008 hurricanes. An additional $260 million in excess of insurance proceeds was expended for the continued abandonment and removal of wreckage from platforms toppled in hurricanes. Cash expended for abandonment activities reduces our asset retirement obligation. The majority of the hurricane abandonment work is now complete.

During 2010 the region plans to invest approximately $1.3 billion to $1.4 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects, seismic acquisition and abandonment activities.

Central Region The Central region includes assets in the Anadarko Basin, the East Texas Basin and the Permian Basin. Over the past decade, the region has grown from approximately 3,000 wells to over 10,000 and now represents 27 percent of Apache s proved reserves, the largest concentration in the Company. The region provides steady, predictable results, enhanced by assets across a large acreage base. During 2009 Apache operated or participated in drilling 135 wells; 99 percent were completed as producers. The region also performed 810 workovers and recompletions.

In 2009 we drilled our first operated horizontal well in the Granite Wash play in Washita County, Oklahoma. The Hostetter #1-23H commenced production in September 2009 at 17 MMcf/d and 800 b/d and is currently producing 9.5 MMcf/d and 600 b/d. Apache owns a 72-percent working interest in the well. The Granite Wash has long been a core-stacked pay target for the Central Region, where we have drilled many vertical wells over the past decade. As a result, we control approximately 200,000 gross acres in the 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 high oil prices given the rich liquids yield of the wells. Hundreds of additional horizontal well locations have been identified across our acreage, extending opportunities for many years. In early 2010 we had three rigs in operation with plans to increase to at least five as we target drilling a minimum of 29 horizontal wells in the play during the year.

During 2010 the Central region plans to invest approximately $325 million to $375 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition in the Anadarko Basin and East Texas. Our newly formed Permian Region plans to invest approximately $375 million to $400 million for similar activities, primarily directed at oil targets.

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 At year-end 2009 our Canadian region held approximately 22 percent of our estimated proved reserves, the second largest concentration in the Company. In our Canadian region, we have 4.4 million net acres across the provinces of British Columbia, Alberta and Saskatchewan. Our acreage base provides a significant inventory of both low-risk development drilling opportunities in and around a number of Apache fields and higher-risk, higher-reward exploration opportunities. In 2009 we drilled or participated in 201 wells in Canada, 41 of which were in the Horn River Basin. Three of the region s wells drilled during the year were exploration wells, all of which were productive.

Apache and EnCana Corporation (EnCana), 50-percent partners, control more than 400,000 acres in the Horn River Basin shale-gas play in northeast British Columbia. We estimate that we could ultimately drill thousands of wells. In 2009 Apache and EnCana drilled 41 wells in the Basin: 23 by Apache and 18 by EnCana. To minimize the environmental footprint and costs, the wells are drilled in batches from multi-well pads. Completion activity commences once drilling operations from a single pad have been completed, allowing room for the equipment needed for fracturing operations to service the entire pad. Four of the EnCana-operated wells were placed on production in 2009 and at year-end were producing at a combined gross rate in excess of 19 MMcf/d. Apache commenced stimulating the 16 wells on its first operated development pad in the fourth quarter of 2009, with production scheduled for mid-2010.

The magnitude of the Horn River resource, its remote location, and the desire to maximize returns prompted Apache to seek alternative markets for its natural gas. On January 13, 2010, we announced that our Apache Canada Ltd. subsidiary agreed to acquire 51-percent ownership and throughput capacity interest in Kitimat LNG Inc. s proposed LNG export terminal in northern British Columbia. We expect to begin front-end engineering and design (FEED) of the project in early 2010. If we proceed with development, Apache s net capacity in the facility will provide an outlet for 350 MMcf/d from Horn River and other areas in Canada, providing access to markets with worldwide LNG prices. Preliminary gross construction cost estimates, which will be refined upon completion of the FEED study, total C$3 billion. A final investment decision (FID) is expected in 2011. If we proceed, initial gas exports are forecast for as early as 2014. Kitimat is designed to be linked to the pipeline system servicing Western Canada s natural gas producing regions via the proposed Pacific Trail Pipelines, a C$1.1 billion project. In association with our acquisition of interest in the Kitimat project, we also acquired a 25.5-percent interest in the proposed pipeline and 350 MMcf/d of capacity rights.

In December 2009, we entered into a farm-in agreement with Corridor Resources Inc. (Corridor) to appraise and potentially develop oil and natural gas resources in the province of New Brunswick. The initial 18-month program is intended to evaluate the commercial potential of natural gas development in the Frederick Brook formation and light oil development at a recent Caledonia oil discovery at a cost to Apache of not less than $25 million. Upon completion of this appraisal program, Apache will have earned a 50-percent working interest in the spacing units drilled. Apache will then have the option to participate in phase two of the program at a cost of not less than $100 million. Upon completion of this phase by March 31, 2013, Apache would earn a 50-percent interest in approximately 116,000 acres.

Our plans for 2010 are to drill or participate in a total of 172 wells in Canada, including 156 development wells and 16 exploratory wells. The planned development wells include 34 new wells in the Horn River Basin, with Apache drilling 18 and EnCana drilling 16. We believe our production will continue to ramp-up in this area throughout 2010 with completion of 55 wells from Apache and its Horn River partner s drilling programs. During 2010 the region plans to invest approximately $1.0 billion to $1.1 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately $100 million of the total is for gathering, transportation and processing (GTP) assets.

On our other core properties, we will focus on oil projects located primarily in Alberta and Saskatchewan to take advantage of the current vast discrepancies between oil and gas 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 (EOR) projects in

Midale, Zama and Provost with long-term plans to develop and expand CO_2 projects. We will continue intermediate-depth gas development drilling in Kaybob and West 5 areas and in Nevis for shallow coal bed methane (CBM) gas. In addition, pursuant to our December 2009 farm-in agreement with Corridor, Apache will commence an appraisal program in New Brunswick in 2010.

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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. Improved North American natural gas pipeline connectivity led to a closer correlation between Canadian and U.S. natural gas prices. 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 2009 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 and our NGLs based on postings, both of which are market-reflective prices, adjusted for quality, transportation and a 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.

Egypt

Overview Egypt holds our largest acreage position, with more than 11 million gross acres in 21 separate concessions (18 producing) that provide us considerable exploration and development opportunities. In addition to being the largest acreage holder in Egypt s Western Desert, we believe that Apache is also the largest producer of liquid hydrocarbons and natural gas in the Western Desert and the third largest in all of Egypt. In 2009 our Egypt region contributed 30 percent of Apache s production revenue, 26 percent of total production and 13 percent of total estimated proved reserves. The Company reports all estimated proved reserves held under production sharing agreements utilizing the economic interest method, which excludes the host country s share of reserves. In 2009 Apache had an active drilling program in Egypt, drilling 164 wells, including nine new field discoveries, and conducted 792 workovers and recompletions. Historically, our growth in Egypt has been driven primarily by exploration and development of internally-generated prospects; in 2009 we were the most active driller in Egypt.

In the Khalda concession in 2009, we continued to monetize our Qasr gas discovery through completion of two additional Salam gas processing facilities, trains three and four, and an associated pipeline compression project on the Western Desert Northern Gas Pipeline. These facility expansions increased flow rates from our Qasr field discovery to 600 MMcf/d and increased total net production in Egypt by 100 MMcf/d and 5,000 b/d.

In Egypt, our operations are conducted pursuant to production-sharing contracts 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. In general, the balance of the production is allocated between the contractor partners and Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis. Development leases within concessions generally have a 25-year life, with extensions possible for additional commercial discoveries or on a negotiated basis.

During 2010 the region plans to invest approximately $1.0 billion to $1.1 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately $150 million of the total is for GTP assets.

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 $3.70 per Mcf in 2009.

Oil from the Khalda Concession, the Qarun Concession and other nearby Western Desert blocks is sold to EGPC when called upon to supply domestic demand and/or to third parties primarily in the Mediterranean market. Oil sales are made either directly into the Egyptian oil pipeline grid, sold to non-governmental third parties including 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 2009 we sold 47 cargoes (approximately 14.7 million barrels) 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 quality oil (approximately 8.5 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 (1.7 MMbbls) or exported primarily to refiners in the Mediterranean region (14 cargoes for approximately 6.8 MMbbls). While we anticipate that an increasing amount of our oil will be sold to meet domestic demand during 2010, we still expect some level of sales to the export market.

Australia

Overview In Australia our exploration activity is focused in the offshore Carnarvon, Gippsland and Browse Basins, where Apache holds 4.3 million net acres in 31 exploration permits, 14 production licenses and three retention leases. We also have one production license and two retention leases pending confirmation. Production operations are concentrated in the Carnarvon and Exmouth Basins. In 2009 the region increased equivalent production 40 percent and accounted for approximately seven percent of our total production. Australia held 13 percent of our year-end estimated proved reserves. During the year the region participated in drilling 33 wells, which generated 28 productive wells.

During 2009 the Australia region restored operations and increased capacity at our Varanus Island gas processing facility, and continued to lay the foundation for future growth by developing previously discovered fields that will come online over the short, intermediate and long terms.

Our growth strategy includes short-term, medium-term and long-term projects from the Carnarvon Basin off the North West shelf of Australia. Both Van Gogh and Pyrenees (two large oil development projects in the Exmouth sub-basin) commenced production in the first quarter of 2010. In the intermediate-term, growth in Australia will result from the development of both Apache s 2008 Halyard discovery and our Reindeer discovery. Both Halyard and Reindeer are gas-development projects that are scheduled to initiate production in 2011. Long-term growth will come from the Company s Julimar, Macedon and Coniston discoveries.

Growth Drivers 2010 Van Gogh is Apache-operated, while Pyrenees is operated by BHP Billiton. Van Gogh development drilling and installation of sub sea production equipment was completed in mid-2009, and limited production commenced in mid-February 2010. Van Gogh oil is produced and stored in the Ningaloo Vision floating, production, storage and offloading (FPSO) vessel, which is still performing normal commissioning activities.

Pyrenees development continued with the drilling and completion of initial wells and installation of subsea facilities in 2009. First oil production commenced ahead of schedule, on February 24, 2010. As planned, the wells will be drilled and brought on in phases, with half of the expected production volume ramping up over the next six months.

Peak production from the Van Gogh and Pyrenees discoveries is projected to reach a combined 40,000 b/d net to Apache.

During 2010 the region plans to invest approximately $1.1 billion to $1.2 billion for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition. Approximately $350 million of the total is for development and processing facilities.

Growth Drivers 2011 In April 2008 we drilled the Halyard-1 discovery well, which tested 68 MMcf/d. Current plans call for the field to be tied into the nearby East Spar gas facilities, with first production anticipated in 2011.

Construction and fabrication work has resumed and official groundbreaking at the Devil Creek site of the onshore gas plant was on September 15, 2009, following completion of a gas sales contract with CITIC Pacific s Sino Iron project in Western Australia. This plant and gas sales contract will enable us to monetize a portion of our

Reindeer gas discovery. Under terms of the agreement, Apache and its joint venture partner have agreed to supply 154 Bcf of gas over seven years (approximately 60 MMcf/d) beginning in the second half of 2011 at prices substantially above Apache s current average realizations. Apache owns a 55-percent interest in the field. The Company is continuing to market its remaining net share in the Reindeer field.

Growth Drivers Long-Term Apache has agreed to participate in an LNG development project (discussed below) that will enable Apache to develop and monetize its share of the Julimar and Brunello natural gas discoveries, opening up new markets for these reserves. Apache s projected net sales are 190 MMcf/d and 5,100 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 tied to oil prices and are currently higher than the historical gas prices in Western Australia.

In October 2009 we announced Apache s 16.25 percent participation with Chevron in the Wheatstone LNG project. The Wheatstone project is targeting a FID in 2011, with first LNG projected in 2015. Apache operates the Julimar and Brunello fields, while Chevron will operate both the Wheatstone field and the LNG facilities. Our net capital investment in the project is currently estimated to be $1.2 billion for upstream development of the Julimar and Brunello fields and $3.0 billion in the Wheatstone facilities.

We have two contingent development opportunities tied to our recent Pyrenees and Van Gogh projects that will be evaluated during 2010. Macedon field is a gas discovery near the Pyrenees field that is currently under review by the operator, BHP Billiton, for commercial development. Gas produced from Pyrenees will be reinjected into Macedon field to reduce flaring and to conserve those volumes for future sale. Coniston field is an oil accumulation near our Van Gogh field. Apache has drilled 10 appraisal wells during 2009 and is evaluating a development plan to tie back the field to the FPSO Ningaloo Vision currently serving the Van Gogh field.

Marketing As of December 31, 2009, Apache had a total of 18 active gas contracts in Australia with expiration dates ranging from March 2010 to July 2030. Historically, natural gas sold in Western Australia was under long-term, fixed-price contracts, many of which contain price escalation clauses based on the Australian consumer price index. The contract in place for the Reindeer field contains prices substantially higher than we currently receive in Australia. The LNG from our Julimar discovery is anticipated to be sold at prices tied to oil and sold into international markets.

Apache continues to directly market all of its crude oil production into Australian domestic and international markets at prices generally indexed to Dated Brent or Tapis benchmarks, which typically track at or above NYMEX oil prices.

North Sea

Overview Apache entered the North Sea in 2003 upon acquiring an approximate 97-percent working interest in the Forties field (Forties). Production for 2009 increased two percent compared to 2008 as gains from our topsides renovation program and our drilling and workover programs more than offset downtime to replace an original vintage spool section at the end of the Bravo-Charlie infield pipeline, which lowered production for the year by 2,690 boe/d.

In addition to an active year of drilling, we completed and made significant progress on several important facility projects that will benefit Forties in the years ahead. The Delta-Charlie infield pipeline was replaced, bringing improved mechanical integrity. We installed and commissioned a new power turbine on Delta to support increasing field-water injection during 2010. On the Charlie platform, we purchased equipment, cleared access and began installing components late in 2009 for a new high-pressure gas lift system that will be operational in early 2011. Work that began on the Echo platform several years ago to replace the antiquated and unreliable controls system with a modern version was fundamentally completed. The various facility upgrade and improvement projects completed in recent years resulted in a significant reduction in the number of occurrences of unplanned downtime. In 2009 we had fewer events causing unplanned downtime than we have experienced in any year since acquiring the Forties field; 64 percent less than our previous best year.

In 2009 the North Sea region produced 22.4 MMboe (99 percent oil), approximately 11 percent of our total worldwide production, generating almost $1.4 billion of revenue and held approximately seven percent of our year-end estimated proved reserves. Our capital investments in the North Sea region during 2009 totaled $354 million.

During 2010 the region plans to invest approximately $625 million to $675 million with significant capital devoted to drilling and improving facilities within Forties. We will also shoot a 3-D seismic survey over Forties to refresh our four-dimensional imaging of bypassed oil accumulations. In 2010 we expect to drill at least one exploration well and one appraisal well in waters outside Forties.

Marketing In 2009 we sold our Forties crude under both term contracts and spot cargoes. The term sales are composed of base-market indices, adjusted for the quality difference between the Forties crude and Brent, with a premium to reflect the higher market value for term arrangements. The value received for spot cargoes, generally about 600,000 barrels each, were at or above prevailing market prices. Apache sold 12 spot cargoes in 2009.

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 and Tierra del Fuego. We have interests in 24 concessions covering over 3.1 million gross acres (2.8 million net), with varying expiration dates, but generally greater than 10 years remaining subject to additional extensions.

Natural gas price realizations in Argentina continued their upward trend in 2009. Our 2009 realized prices were $1.96 per Mcf, a 22 percent increase over our 2008 averaged realized price of $1.61 per Mcf and a 68 percent increase over the $1.17 per Mcf realized in 2007.

During 2009 Apache received technical and commercial approval from the government of Argentina for four Gas Plus projects and technical approval for two more Gas Plus projects designed to encourage new supplies through development of tight sands and unconventional gas reserves. Under the Gas Plus program, Apache has the opportunity to supply 10 MMcf/d from fields in the Neuquén Province at a price of $4.10 per MMBtu beginning January 2010 for an initial one-year term. The Company also has signed a letter of intent for a contract to supply up to 50 MMcf/d from fields in the Neuquén and Rio Negro Provinces for $5.00 per MMBtu beginning January 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 this type of program, coupled with changing market conditions, points to improving price realizations going forward.

In December 2008 the Mendoza Province granted Apache an exploration permit for CCyB Block 17B in the Cuyo Basin, which increased our Argentine acreage by 34 percent. Apache is currently awaiting Mendoza Province s approval for the extension of CCyB Block 17A, which is anticipated in the first half of 2010. Together the two Mendoza Province blocks comprise about 1.2 million acres. Approximately 505 square kilometers of 3-D seismic is scheduled to be acquired in 2010 using new cable-less technology, the first time this technology has been used in Argentina. A drilling campaign in the Cuyo Basin is also scheduled to commence in mid-2010. With the addition of the Mendoza acreage, Apache will hold oil and gas assets in three of the main Argentine hydrocarbon basins: Neuquén, Austral and Cuyo.

In March 2009 the Province of Neuquén and Apache reached agreement 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.

Activity during 2009 on our Tierra del Fuego assets included nine discoveries, several facility projects and a fracture stimulation campaign involving 10 wells. 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 deadlines, which are scheduled to expire in 2016 and 2017.

In 2009 our Argentina region produced 16.6 MMboe, drilled 29.6 net wells (32 gross) and performed 57 additional capital projects. These programs added an estimated 14.4 MMboe in reserves and bring our reserves in Argentina to an estimated 119.0 MMboe at December 31, 2009, or five percent of our estimated worldwide total.

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During 2010 the region plans to invest approximately $250 million for drilling, recompletion projects, development projects, equipment upgrades, production enhancement projects and seismic acquisition.

Marketing 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 2009 we realized an average price of $1.07 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 2009. Our overall average realized price for 2009 was $1.96 per Mcf, 22 percent higher than 2008 average realized prices ($1.61 per Mcf) and 68 percent higher than 2007 average realized prices ($1.17 per Mcf).

Taxes on exported oil effectively limit 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, 2009 oil prices realized from our Neuquén Basin production averaged $44.09 per barrel, compared to $54.43 per barrel from our Tierra del Fuego oil production.

Apache realized an additional $6 million of oil revenues in 2009 from benefits generated by the government s Oil Plus Program. This program rewarded participants that increased oil production and reserves during 2008 and 2009. A further $2 million of benefit was realized in January 2010.

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. Two of the wells reached total depth by year-end 2009, with drilling completed on the third well in early 2010. Currently a completion rig is conducting testing and completion efforts on the three wells. During 2010 we plan to invest approximately $25 million to $35 million for drilling and seismic acquisition.

Major Customers

In 2009 purchases by Shell accounted for 18 percent of the Company s worldwide oil and gas production revenues.

Subsequent Events

Kitimat LNG Terminal

On January 13, 2010, Apache announced that its Apache Canada Ltd. subsidiary has agreed to acquire 51 percent of Kitimat LNG Inc. s proposed LNG export terminal in British Columbia. Apache also reserved 51 percent of gas throughput capacity in the terminal.

The proposed Kitimat project, located at Bish Cove near the Port of Kitimat about 405 miles north of Vancouver, has planned capacity of about 700 MMcf/d, or five million metric tons of LNG per year. Preliminary gross construction cost estimates of C$3 billion will be refined at the conclusion of FEED. The project is projected to employ an estimated 1,500 people during construction and 100 on a permanent basis.

Kitimat is designed to be linked to the pipeline system servicing Western Canada s natural gas producing regions via the proposed Pacific Trail Pipelines, a C$1.1 billion project. In association with our acquisition of interest in the Kitimat project, we also acquired a 25.5-percent interest in the proposed pipeline and 350 MMcf/d of capacity rights.

2010 Performance Program

To provide long-term incentives for Apache employees to deliver competitive returns to our stockholders, in January 2010 the Company s Board of Directors approved the 2010 Performance Program, pursuant to the 2007

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Omnibus Equity Compensation Plan. Eligible employees received an initial conditional restricted stock unit award of 541,440 units, with the ultimate number of restricted stock units to be awarded, if any, based upon measurement of total shareholder return of Apache common stock as compared to a designated peer group during a three-year performance period. Should any restricted stock units be awarded at the end of the three-year performance period, 50 percent of restricted stock units awarded will immediately vest, and an additional 25 percent will vest on succeeding anniversaries of the end of the performance period. The Company s Board of Directors also approved a one-time restricted stock unit award of 502,470 shares to eligible Apache employees, with one-third of the units granted immediately vesting and an additional one-third vesting on each of the first and second anniversaries of the grant date.

Drilling Statistics

Worldwide in 2009 we participated in drilling 610 gross wells, with 558 (91 percent) completed as producers. We also performed nearly 2,100 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: 12 in the U.S. (8.1 net); 5 in Canada (3.6 net); 14 in Egypt (13.0 net); 9 in Australia (3.1 net); 2 in the North Sea (1.9 net); and 2 in Argentina (2 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
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
2007									
United States	3.0	3.1	6.1	264.9	16.5	281.4	267.9	19.6	287.5
Canada	9.5	15.5	25.0	206.0	35.4	241.4	215.5	50.9	266.4
Egypt	10.7	13.0	23.7	144.3	14.8	159.1	155.0	27.8	182.8
Australia	3.8	7.2	11.0	2.7		2.7	6.5	7.2	13.7
North Sea		2.5	2.5	4.9	6.8	11.7	4.9	9.3	14.2
Argentina	2.0		2.0	80.8	2.0	82.8	82.8	2.0	84.8
Total	29.0	41.3	70.3	703.6	75.5	779.1	732.6	116.8	849.4

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, 2009, is set forth below:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	830	655	967	712	1,797	1,367

Central	3,350	1,765	7,690	5,358	11,040	7,123
Canada	8,355	7,373	2,215	982	10,570	8,355
Egypt	45	45	660	640	705	685
Australia	12	8	32	20	44	28
North Sea			74	72	74	72
Argentina	410	372	550	473	960	845
Total	13,002	10,218	12,188	8,257	25,190	18,475

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Production, Pricing and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, natural gas liquids (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 (Mbbls)	Production NGLs (Mbbls)	Production Gas (MMcf)	Average Lease Operating Cost per Boe	Average Sales Price Oil (Per bbl)	Average Sales Price NGLs (Per bbl)	Average Sales Price Gas (Per Mcf)
2009							
United States	32,534	2,239	243,121	$ 10.59	$ 59.06	$ 33.02	$ 4.34
Canada	5,543	763	131,121	11.46	56.16	25.54	4.17
Egypt	33,631		132,355	5.17	61.34		3.70
Australia	3,569		67,020	6.84	64.42		1.99
North Sea	22,259		987	8.19	60.91		13.15
Argentina	4,199	1,183	67,363	6.78	49.42	18.76	1.96
Total	101,735	4,185	641,967	$ 8.48	$ 59.85	$ 27.63	$ 3.69
2008							
United States	32,866	2,191	248,835	$ 12.62	$ 83.70	$ 58.62	$ 8.86
Canada	6,278	760	129,099	14.00	93.53	49.33	7.94
Egypt	24,431		96,518	6.47	91.37		5.25
Australia	3,019		45,019	9.85	91.78		2.10
North Sea	21,775		965	10.00	95.76		18.78
Argentina	4,542	1,056	71,609	6.58	49.46	37.83	1.61
Total	92,911	4,007	592,045	$ 10.56	$ 87.80	$ 51.38	$ 6.70
2007							
United States	33,127	2,811	280,903	$ 10.55	$ 66.48	$ 45.24	$ 7.04
Canada	6,846	820	141,697	12.36	68.29	40.55	6.30
Egypt	22,168		87,883	5.16	72.51		4.60
Australia	5,029		71,149	4.81	79.79		1.89
North Sea	19,576		705	10.61	70.93		15.03
Argentina	4,175	1,022	73,330	4.81	45.99	37.78	1.17
Total	90,921	4,653	655,667	$ 8.90	$ 68.84	$ 42.78	$ 5.34

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	2,133,890	1,347,842	2,854,176	1,762,757
Canada	2,231,460	1,782,795	3,335,057	2,639,663
Egypt	9,797,481	6,336,803	1,313,280	1,208,331
Australia	5,843,110	3,886,650	744,776	402,500
North Sea	341,195	237,380	41,019	39,846
Argentina	2,889,000	2,610,000	259,000	194,000
Chile	1,203,608	1,034,841		
Total	24,439,744	17,236,311	8,547,308	6,247,097

As of December 31, 2009, we had 2,948,251, 2,941,882 and 928,515 net acres scheduled to expire by December 31, 2010, 2011 and 2012, 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 expect a significant portion of our net acreage position to expire before such actions occur.

As of December 31, 2009, 78 percent of U.S. net undeveloped acreage and 44 percent of Canadian undeveloped acreage was held by production.

Estimated Proved Reserves and Future Net Cash Flows

In January 2009 the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting (Release 33-8995), amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. 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. In January 2010 the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which amends Accounting Standards Codification (ASC) Topic 932, Extractive Industries Oil and Gas to align the guidance with the changes made by the SEC. The Company adopted Release 33-8995 and the amendments to ASC Topic 932 resulting from ASU 2010-03 (collectively, the Modernization Rules) effective December 31, 2009.

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.

Proved undeveloped (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, 2009, based on average commodity prices in effect on the first day of each month in 2009, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms.

	Oil (MMbbls)	NGL (MMbbls)	Gas (MMcf)	Total (MMboe)
Proved Developed:				
United States	344	29	1,785	671
Canada	79	10	1,436	329
Egypt	98		838	237
Australia	33	1	700	151
North Sea	142		5	143
Argentina	19	7	473	105
Proved Undeveloped:				
United States	144	6	653	260
Canada	56	1	869	202
Egypt	18		321	71
Australia	44		662	154
North Sea	30			30
Argentina	5	1	54	14
TOTAL PROVED	1,012	55	7,796	2,367

As of December 31, 2009, Apache had total estimated proved reserves of 1,067 MMbbls of crude oil, condensate and NGLs and 7.8 Tcf of natural gas. Combined, these total estimated proved reserves are the energy equivalent of 2.4 billion barrels of oil or 14.2 Tcf of natural gas. As of December 31, 2009, the Company s proved developed reserves totaled 1,636 MMboe, and estimated PUD reserves totaled 731 MMboe, or approximately 31 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, 2009, 2008, 2007 and 2006, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 13 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, 2009, 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 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, and 2007, were estimated using commodity prices in effect at the end of those years, in accordance with the SEC guidelines in effect prior to the issuance of the Modernization Rules.

Proved Undeveloped Reserves

The Company s total estimated proved undeveloped reserves of 731 MMboe as of December 31, 2009, increased by 54 MMboe over the 677 MMboe of PUD reserves estimated at the end of 2008. During the year, Apache converted 39 MMboe of proved undeveloped reserves to proved developed reserves through development drilling activity. In North America we converted 22 MMboe with the remaining 17 MMboe in our international areas.

During the year a total of $760 million was spent on projects associated with reserves that were carried as PUD reserves at the end of 2008. Not all of those expenditures resulted in a conversion from proved undeveloped to proved developed reserves during the year. We spent $264 million on PUD reserve development activity in North America and $496 million in the international areas, including $230 million in Australia where the reserves for those projects will be converted to developed in future years.

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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. As additional geoscience, engineering and economic data are obtained, proved reserve estimates are much more likely to increase or remain constant than to decrease. 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, W. Kregg Olson, 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. Mr. Olson is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. He has over 29 years of industry experience, with the last 25 years focused on reservoir engineering. He is a member of the Society of Petroleum Engineers and is a Registered Professional Engineer in the state of Oklahoma. Mr. Olson has held positions of increasing responsibility within Apache s corporate reservoir engineering department since joining the company in 1992.

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. These properties represented all material fields, and over 85 percent of international properties and new wells drilled during the year. During 2009, 2008, and 2007, Ryder Scott s review covered 79, 82 and 77 percent of the Company s worldwide estimated reserves value, respectively. We have filed Ryder Scott s independent report as an exhibit to this Form 10-K.

Ryder Scott opined that the overall proved reserves for the reviewed properties as estimated by the Company are, in the aggregate, reasonable, prepared in accordance with generally accepted petroleum engineering and evaluation principles and conform to the SEC s definition of proved reserves as set forth in Rule 210.4-10(a) of Regulation S-X. Ryder Scott has informed the Company that the tests and procedures used during its reserves audit conform to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information approved by the Society of Petroleum Engineers. Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information defines a reserves audit as the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed, (2) the adequacy and quality of the data relied upon, (3) the depth and thoroughness of the reserves estimation process, (4) the classification of reserves appropriate to the relevant definitions used, and (5) the reasonableness of the estimated reserve quantities. A reserve audit is not the same as a financial audit and is less rigorous in nature than an independent reserve report where the independent reserve engineer determines the reserves on his or her own.

Employees

On December 31, 2009, we had 3,452 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 2009 we maintained regional exploration and/or production offices in

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Tulsa, Oklahoma; Houston, 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.

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 recession that began in 2008 and extended into 2009. Growth has resumed but is modest. 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 we have experienced in recent years. In addition, more volatility may occur before a sustainable growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

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

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2009 ranged from a high of $81.37 per barrel to a low of $33.98 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 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;

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- 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 2009. If commodity prices decline during 2010, 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.

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

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

our production falls short of the hedged volumes;

there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;

the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or

a sudden unexpected event materially impacts oil and natural gas prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. 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, reserve mix and commodity pricing levels could also be considered by the rating agencies. Apache s senior unsecured long-term debt is currently rated A3 by Moody s, A- by Standard & Poor s and A- by Fitch. The Company has received short-term debt ratings for its commercial paper program of P-2 from Moody s, A-2 from Standard & Poor s and F2 from Fitch. In September 2009 Fitch downgraded Apache s senior unsecured long-term debt and short-term debt from A and F1 to A- and F2, respectively. The current outlook at all three rating agencies is stable. A further 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 in certain circumstances.

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

During 2009 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.

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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.

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

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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 associated 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.

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;
- assumptions concerning future crude oil and natural gas prices;
- 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.

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 affect 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, Canada, the United Kingdom and the United States, 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 2009, only two of the jurisdictions in which the Company has operations, Alberta, 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.

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The proposed U.S. federal budget for fiscal year 2011 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 1, 2010, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2011. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; repeal of the manufacturing tax deduction for oil and natural gas companies; and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also 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 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.

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 2009 production was outside North America and approximately 38 percent of our estimated proved oil and gas reserves on December 31, 2009 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.

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.

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ITEM 1B. *UNRESOLVED SEC STAFF COMMENTS*

As of December 31, 2009, 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. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

No matters were submitted to a vote of our security holders during the most recently ended fiscal quarter.

PART II

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

During 2009 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 2009 and 2008. 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.

	2009				2008			
	Price Range		Dividends Per Share		Price Range		Dividends Per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 88.07	$ 51.03	$ .15	$ .15	$ 122.34	$ 84.52	$ .25	$ .25
Second Quarter	87.04	61.60	.15	.15	149.23	117.65	.15	15
Third Quarter	95.77	65.02	.15	.15	145.00	94.82	.15	.15
Fourth Quarter	106.46	88.06	.15	.15	103.17	57.11	.15	.15

The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 29, 2010 (last trading day of the month), was $98.77 per share. As of January 31, 2010, there were 336,550,234 shares of our common stock outstanding held by approximately 5,800 stockholders of record and approximately 442,000 beneficial owners.

We have paid cash dividends on our common stock for 45 consecutive years through December 31, 2009. 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, 2004, through December 31, 2009.

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

* $100 invested on 12/31/04 in stock including reinvestment of dividends.
Fiscal year ending December 31.

	2004	2005	2006	2007	2008	2009
Apache Corporation	$ 100.00	$ 136.28	$ 133.14	$ 216.91	$ 151.34	$ 211.14
S & P s Composite 500 Stock Index	100.00	104.91	121.48	128.16	80.74	102.11
DJ US Expl & Prod Index	100.00	165.32	174.20	250.27	149.86	210.65

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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, 2009, 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, (In thousands, except per share amounts)				
	2009	**2008**	**2007**	**2006**	**2005**
Income Statement Data					
Total revenues	$ 8,614,826	$ 12,389,750	$ 9,999,752	$ 8,309,131	$ 7,584,244
Income (loss) attributable to common stock	(291,692)	706,274	2,806,678	2,546,771	2,618,050
Net income (loss) per common share:					
Basic	(.87)	2.11	8.45	7.72	7.96
Diluted	(.87)	2.09	8.39	7.64	7.84
Cash dividends declared per common share	.60	.70	.60	.50	.36
Balance Sheet Data					
Total assets	$ 28,185,743	$ 29,186,485	$ 28,634,651	$ 24,308,175	$ 19,271,796
Long-term debt	4,950,390	4,808,975	4,011,605	2,019,831	2,191,954
Shareholders equity	15,778,621	16,508,721	15,377,979	13,191,053	10,541,215
Common shares outstanding	336,437	334,710	332,927	330,737	330,121

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 engaged in worldwide crude oil, natural gas and NGL exploration and production. In North America, our exploration and production operations are focused in the Gulf of Mexico, the Gulf Coast, East Texas, the Permian Basin, the Anadarko Basin and the Western Sedimentary Basin of Canada. Outside of North America, we have exploration and production operations onshore Egypt, offshore Western Australia, offshore the United Kingdom (U.K.) in the North Sea (North Sea), and onshore Argentina. We also have exploration interests on the Chilean side of the island of Tierra del Fuego.

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 upstream oil and gas company for the long-term benefit of our shareholders. Apache s long-term perspective has many dimensions, with the following core principles:

- Own a balanced portfolio of core assets;
- Maintain financial flexibility and a strong balance sheet; and
- Optimize rates of return, earnings and cash flow.

Throughout the cycles of our industry, these strategies have underpinned our ability to deliver 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 24 years and production 29 out of the past 31 years, a testament to our consistency over the long-term.

These strategies have served us well in the past and should continue to serve us well going forward. However, we also believe several long-term trends across the globe will have a tremendous impact on supply and demand for fuel and on Apache s business model in the years ahead.

- Demand for fuel continues to grow in many parts of the developing world, where billions of people are seeking to move up the economic ladder.
- A new psychology of scarcity is driving competition for resources around the world and testing many long-held assumptions and relationships. The world will need all sources of energy including wind, solar and other alternatives to keep up with long-term demand growth.
- In North America, recent improvements in horizontal drilling and completion technology have transformed the natural gas market, opening up a 100-year resource with the potential to improve U.S. energy security, create jobs and help achieve environmental and climate change goals.

We believe Apache s evolution from a domestic driller and producer to an independent global exploration and production company, coupled with our sense of urgency, discipline, innovation and spirit, positions us well to take advantage of these impending trends. Our current production base provides the cash flow required for us to seek out larger exploration targets while developing our discoveries, including Qasr in Egypt, Julimar in Australia and the Horn River Basin of British Columbia.

As we head into 2010, we anticipate that higher production will generate adequate cash flow to support a higher activity level compared to 2009. Two oil developments in Australia Van Gogh and Pyrenees will contribute significant volumes in 2010. Also, gas production in the Horn River Basin shale play will begin ramping up in 2010 as Apache s teams apply technological innovations to complete wells more quickly and at lower cost.

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However, while we are comfortable that our $2 billion of cash on hand at year-end and the additional liquidity available from our credit facilities will provide ample flexibility to pursue additional exploration activity or opportunistic, value-adding acquisitions, lingering issues in the credit markets clearly demonstrate that any detectable economic recovery is fragile at best. Therefore, we will continue to manage drilling and development capital spending in line with available cash flow.

Financial and Operating Results

The dramatic decline in oil and gas prices and global financial crisis that began in 2008 provided the backdrop for our primary objective in 2009: living within our cash flow to preserve financial flexibility. Although we curtailed activity to achieve this objective, Apache delivered record annual average daily production up nine percent from 2008 and added slightly more reserves, excluding revisions, than we produced.

The decline in oil and gas prices impacted Apache s 2009 financial results, requiring us to reduce the carrying value of oil and gas properties and resulting in a $1.98-billion non-cash charge to earnings during the first quarter. However, with rebounding oil prices and higher production, earnings strengthened throughout the remainder of the year.

To ensure we lived within cash flow, we reduced 2009 activity and investments to $4.1 billion, 39 percent below 2008 levels. Despite curtailed capital spending, we moved forward on several large development projects, pursued exploration opportunities resulting in several important new discoveries, increased production nine percent to a record 583,328 boe/d and generated $4.2 billion in net cash provided by operating activities. In addition, we maintained our strong balance sheet and ample liquidity levels, exiting 2009 with a debt-to-capitalization ratio of 24 percent, just over $2 billion of cash and $2.3 billion in available committed borrowing capacity. We also believe our single-A debt ratings provide a competitive advantage in accessing capital.

For the year, Apache recorded a net loss of $292 million, or $.87 per common diluted share, compared to 2008 net income of $706 million, or $2.09 per common diluted share. Apache s 2009 reported adjusted earnings (1) , which exclude certain items impacting the comparability of results, were $1.98 billion or $5.59 per common diluted share, down from $3.8 billion or $11.22 per common diluted share in the prior year. We generated net cash provided by operating activities totaling $4.2 billion, down from $7.1 billion in 2008.

The following items impacted our 2009 earnings and cash flow as compared to 2008:

- Record production of 583,328 boe/d, up nine percent from 2008;
- Average realized oil prices decreased 32 percent to $59.85 per bbl;
- Average realized gas prices decreased 45 percent to $3.69 per Mcf;
- A non-cash after-tax write-down of the carrying value of proved property of $1.98 billion in 2009 versus $3.6 billion in 2008 affected earnings; and
- Total operating expenses decreased $3.2 billion, or 28 percent, from 2008.

(1) See *Results of Operations 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.

Proposed Climate Change Legislation

Management believes that climate change legislation globally is undergoing a phase of significant evolution, and as a consequence, the Company perceives an unusual lack of clarity surrounding this issue. Furthermore, in the United States, the Company is concerned that legislation will distort markets and protect other energy sectors. The Company believes that natural gas offers the most cost effective means to reduce greenhouse gas (GHG) emissions rapidly and the Company is well positioned to contribute to an overall increase of natural gas supply.

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Apache Greenhouse Gas Emissions Reporting

Total gross GHG emissions from Apache operated properties world-wide are calculated and reported to the Carbon Disclosure Project (CDP) on a country-by-country basis using recognized international protocols. Currently the CDP maintains a public access website with Apache information for calendar year 2008. Emissions for calendar year 2009 are due to be reported to CDP by May for posting later in 2010. Readers are advised that Apache GHG emissions values are not subject to the same rigorous controls for accuracy and reliability as financial data found in this filing, and that there are inherent limitations for directly measuring GHG emissions from oil and gas production facilities in general.

In addition, for required facilities, Apache GHG emissions are reported to local and national authorities in Australia, Canada and the United Kingdom following reporting standards specific to each jurisdiction, and verified according to regulatory requirements. For 2010, the United States Environmental Protection Agency will require emissions reports covering some of our largest fixed combustion facilities.

Operating Highlights

Operational highlights for the year and growth drivers for 2010 and beyond are as follows:

Australia

During 2009 the Australia region restored operations and increased capacity at the Varanus Island gas processing facility, and it continued to lay the foundation for future growth by developing previously discovered fields that will come on-line over the short, intermediate and long terms. Our Van Gogh and Pyrenees discoveries (oil fields) commenced production in the first quarter of 2010. In the intermediate-term, our Halyard and Reindeer discoveries (gas fields) are scheduled to begin producing in 2011. In the longer term, we will see additional production from our Julimar, Macedon and Coniston field discoveries, as discussed below.

Discoveries expected to begin producing in 2010

Van Gogh Discovery Development Drilling and installation of subsea production equipment were completed in 2009 at the Apache-operated Van Gogh field discovery. Limited production began in February 2010, with routine commissioning activities still being performed on the floating, production, storage, and offloading vessel (FPSO) servicing the field.

Pyrenees Discovery Development Installation of subsea facilities at our Pyrenees field was completed in 2009. First oil production commenced ahead of schedule, on February 24, 2010. As planned, the wells will be drilled and brought on in phases, with half of the expected production volume ramping up over the next six months.

Peak production from the Van Gogh and Pyrenees discoveries is projected to reach a combined 40,000 b/d net to Apache.

Discoveries expected to begin producing in 2011

Halyard Discovery Development In April 2008 we drilled the Halyard-1 discovery well, which tested 68 MMcf/d. We currently plan to tie the field into the existing nearby East Spar gas facilities. First production is anticipated in 2011.

Reindeer Discovery Development Our Reindeer field discovery will be produced through an onshore gas plant currently under construction, the Devil Creek gas plant. 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 second half of 2011 at prices higher than we have historically received in Western Australia. Apache owns a 55-percent interest in the field. The company is continuing to market its remaining net share in the Reindeer field.

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Discoveries expected to begin producing after 2011

Julimar and Brunello Natural Gas Discoveries Our Julimar and Brunello natural gas discoveries will be produced through liquefied natural gas (LNG) facilities (discussed below). The LNG project, which is currently in front-end engineering and design (FEED), will convert the gas into LNG for sale on the world market. World LNG prices are typically tied to oil prices, and are currently higher than gas prices we have historically received in Western Australia. Our projected net sales would approximate 190 MMcf/d and 5,100 b/d with a projected 15-year production plateau when the multi-year project is complete and all the wells are producing.

Wheatstone LNG Project In October 2009, Apache announced an agreement to become a foundation equity partner in Chevron s Wheatstone LNG hub in Western Australia. Chevron, which has a 100-percent interest in the Wheatstone field, will operate the LNG facilities with a 75-percent interest. Apache will own 16.25 percent interest in the project and our partner in the Julimar and Brunello fields will own the remaining project interest. The Wheatstone project is targeting a final investment decision (FID) in 2011 and first sales from the facility are projected for 2015. Our net capital for the project is currently estimated to be $1.2 billion for upstream development of the Julimar and Brunello fields and $3.0 billion in the Wheatstone facilities. The investment will be funded as the multi-year project is developed.

Macedon and Coniston Discoveries We have two contingent development opportunities that will be evaluated during 2010. The Macedon field is a gas discovery near our Pyrenees field which is currently being reviewed by the operator, BHP Billiton, for commercial development. Gas produced from Pyrenees will be reinjected into the Macedon field to reduce flaring and conserve those volumes for future production. The Coniston field is an oil accumulation near our Van Gogh field. Apache drilled 10 appraisal wells during the year and is evaluating a development plan to tie-back the field to the FPSO currently serving the Van Gogh field.

Egypt

Notable successes during the year include:

2X Project

In June 2005, Apache and the Egyptian government set a goal to double gross equivalent production from Apache operated concessions by the end of 2010 (2X Project). At the time of the proposal, Apache s gross operated equivalent production was approximately 163 Mboe/d. As we exited 2009, Egypt was over 90 percent of the way to reaching that goal.

Double-digit Growth in both oil and gas production

Egypt s gross gas production increased 26 percent, driven by exploration successes at our Khalda and Matruh concessions and from 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 pipeline allowed previously discovered wells in the Khalda Concession Qasr field to come online. The increased compression in the Northern Gas Pipeline also allowed increased throughput at the nearby Tarek plant and enabled us to begin producing previous discoveries at the Jade and Falcon fields in our Matruh concession.

Egypt s gross oil production increased 25 percent on exploration successes in numerous concessions, most notably East Bahariya Extension, South Umbarka, Matruh, NEAG Extension and Khalda. Waterflood projects and increased condensate from additional Qasr gas flowing through the new processing trains at Salam Gas Plant also contributed.

Additional plant and pipeline capacity expansion will be required in the coming years to keep pace with the internally-generated discoveries described below.

Development, Exploration and Appraisal Activity

Phiops Field Discovery Kalabsha Concession Current production from the Phiops field, initially discovered in late 2008, is approximately 8,100 b/d gross, with two of four completed wells shut-in due to facility constraints. The Phiops field is the largest of five fields discovered in the Faghur Basin of the Western Desert since 2006 by Apache through its joint venture partner, Khalda Petroleum Company. We expect to increase production to 20,000 gross barrels per day when additional infrastructure is completed by mid-2010. To allow for future production growth, a second phase of infrastructure expansion to 40,000 b/d, is targeted for completion by the end of the third quarter of 2010. In addition, gas capacity of 38 MMcf/d is slated for mid-2011. Further exploration, appraisal and development activity in the concession is planned for 2010.

Concession Extensions Amendments to extend our Siwa, Sallum, and West Ghazalat exploration concessions for an additional three years (to July 27, 2013) were approved by the Egyptian Parliament in June 2009. These concessions encompass 3.8 million gross acres, which Apache operates with a 50-percent contractor interest. Seismic acquisition and early exploration drilling is planned for 2010. Additionally, we finalized extension of the Khalda Offset and East Bahariya concessions in the Western Desert. At Khalda Offset, the exploration phase is extended until July 2016. Apache has a 100-percent contractor interest in this concession, which covers 909,000 acres. The East Bahariya concession exploration phase was extended through July 2012. Apache has a 100-percent contractor interest in this concession, which encompasses 674,000 acres.

North Tarek Concession On April 30, 2009, we announced the NTRK-C-1X well, our first discovery in this concession along the Mediterranean coast, tested at a rate of 3,489 b/d and 5 MMcf/d. Additional drilling is planned for 2010.

Shushan C Concession Hydra Field Apache has had numerous exploration successes on this concession and is in the process of negotiating a Gas Sales Agreement with Egyptian General Petroleum Corporation (EGPC). When the agreement is completed, we will file to establish a development lease. The most recent discovery, the Hydra-5X appraisal well, tested 21 MMcf/d and 3,744 b/d. This well follows Apache s Hydra-1X discovery drilled in 2008 which test-flowed 76.6 MMcf/d and 2,813 b/d.

Other Discoveries During 2009 we had three additional discoveries in Egypt s Western Desert that tested an aggregate 80 MMcf/d and 5,909 b/d. The Sultan-3X located on the Khalda Offset Concession test-flowed 5,021 b/d and 11 MMcf/d. The two other discoveries, the Adam-1X and the Maggie-1X, discovered new gas-condensate fields on the Matruh development lease north of the Sultan discovery. Apache has a 100-percent contractor interest in both concessions. Oil production from Sultan-3X began in the first quarter of 2009.

North America

Apache s North American asset base, comprised of the U.S. Central and Gulf Coast Regions along with Canada, reflects the balanced portfolio approach that has long been one of the Company s greatest strengths. The Central Region provided steady, predictable results with its high-quality assets and large acreage base. The Gulf Coast Region delivered solid production despite curtailment of capital spending. Also, the region restored virtually all production shut-in by hurricanes. Canada laid the foundation for future growth through its shale-gas plays and Kitimat LNG acquisition. Operating highlights for 2009 and future growth drivers for our North American operations include the following:

U.S. Central Region

During the second quarter of 2009 we announced the acquisition of nine Permian Basin oil and gas fields with current net production of 3,500 barrels of oil equivalent per day from Marathon Oil Corporation for $187.4 million, subject to normal post-closing adjustments. These long-lived oil fields fit well with Apache s existing properties in the Permian Basin, particularly in Lea County, N.M., and will provide us drilling opportunities for many years. The effective date of the transaction was January 1, 2009.

In 2009 we drilled our first operated horizontal well in the Granite Wash play in Washita County, Oklahoma. The Hostetter #1-23H commenced production in September 2009 at 17 MMcf/d and 800 b/d and is currently producing 9.5 MMcf/d and 600 b/d. Apache owns a 72-percent working interest in the well. We have drilled extensively over the past decade in the Granite Wash, and as a result, we control approximately 200,000 gross acres in the play, mostly held-by-production. Hundreds of additional horizontal well locations have been identified across our acreage, extending opportunities for many years. In early 2010 we had three rigs in operation with plans to increase to at least five as we target drilling a minimum of 29 horizontal wells in the play during the year.

U.S. Gulf Coast Region

In April 2009 we announced a key deepwater discovery at Ewing Banks Block 998 that test-flowed 4,254 b/d and 5.4 MMcf/d. The well will be connected to existing facilities, with first production projected for mid-year 2010. Apache owns a 50-percent interest in the property.

In May 2009 production commenced from two deepwater discoveries in the Geauxpher field, located on Garden Banks Block 462. During the second half of 2009, the field produced an average of 91 MMcf/d gross. Apache generated the prospect and has a 40-percent working interest.

At South Timbalier 287 (drilled from Apache s South Timbalier 308 platform), the #A-8 well came online flowing 1,800 b/d. Apache has a 100-percent working interest in this well.

At Ewing Banks 826, four successful wells were drilled as part of our redevelopment program. Initial production rates ranged from 500 b/d to 1,000 b/d per well. Apache has a 100-percent working interest in these wells.

A relatively quiet hurricane season allowed the region to continue restoration of shut-in production in the Gulf of Mexico. We made considerable progress, and virtually all production shut-in by hurricanes has been restored.

Canada

Unconventional gas opportunities in Canada are anticipated to drive future growth of Apache s Canadian region, moving beyond conventional plays in Alberta, British Columbia and Saskatchewan that have been the foundation of the region s activities for 15 years.

Horn River Basin Shale Gas Play Apache continued development activity on its Horn River Basin shale-gas play in northeast British Columbia, where we have over 220,000 highly prospective net acres. During 2009 Apache and its joint interest partner drilled 41 horizontal wells. Four of these wells were completed and placed on production by year-end 2009 and were producing at a combined gross rate in excess of 19 MMcf/d. Apache commenced stimulating the 16 wells on its first operated development pad in the fourth quarter of 2009, with production scheduled for mid-2010. A total of 55 wells are planned for completion in 2010. Additionally, during the second quarter of 2009, a new dehydration and compressor facility and a new 42-mile 24-inch sales line, with capacity of over 700 MMcf/d, was commissioned that will allow us to flow gas to a third-party interconnect point when completed in 2010.

Kitimat LNG Terminal The expected magnitude of the Horn River Basin resources and its remote location far from most major North American markets prompted Apache to seek alternative markets. In January 2010 we announced an agreement to acquire a 51-percent interest in Kitimat LNG, Inc s. proposed LNG export terminal in British Columbia. We also reserved 51 percent of throughput capacity in the terminal. Planned plant capacity will be approximately 700 MMcf/d, or five million metric tons of LNG per day. This project has the potential to access new markets in the Asia-Pacific region and allow Apache to monetize gas from its Canadian region, including its interest in the Horn River Basin in northeast British Columbia. A final investment decision is expected in 2011, with the first LNG shipments projected for as early as 2014. Apache will become the operator of the project. Preliminary gross construction cost estimates, which will be refined upon completion of a FEED study, total C$3 billion. Kitimat is designed to be linked to the pipeline system servicing Western Canada s natural gas producing regions via the proposed Pacific Trail

Pipelines, a project with a current estimated gross cost of C$1.1 billion. In association with our acquisition of interest in the Kitimat project, we also acquired a 25.5-percent interest in the proposed pipeline and 350 MMcf/d of capacity rights.

Corridor Resources, Inc. Farm-in In December 2009, we entered into a farm-in agreement with Corridor Resources Inc. (Corridor) to appraise and potentially develop oil and natural gas resources in the province of New Brunswick, Canada. The initial 18-month program is intended to evaluate the commercial potential of natural gas development in the Frederick Brook formation and light oil development at a recent Caledonia oil discovery at a cost to Apache of not less than $25 million. Upon completion of this appraisal program, Apache will have earned a 50-percent working interest in the spacing units drilled. Apache will then have the option to participate in phase two of the program at a cost of not less than $100 million. Upon completion of this phase by March 31, 2013, Apache would earn a 50-percent interest in approximately 116,000 acres.

North Sea

Apache entered the North Sea in 2003 upon acquiring an approximate 97-percent working interest in the Forties field (Forties). Production increased two percent in 2009, as gains from our drilling and workover programs more than offset unplanned downtime to replace an original vintage spool section at the end of the Bravo-Charlie infield pipeline, which lowered production for the year by 2,690 boe/d.

In addition to an active year of drilling, we completed and made significant progress on several important facility projects that will benefit Forties in the years ahead. The Delta-Charlie infield pipeline was replaced, bringing improved mechanical integrity. We installed and commissioned a new power turbine on Delta to support increasing field-water injection during 2010. On the Charlie platform, we purchased equipment, cleared access and began installing components late in 2009 for a new high-pressure gas lift system that will be operational in early 2011. Work that began on the Echo platform several years ago to replace the antiquated and unreliable controls system with a modern version was fundamentally completed. The various facility upgrade and improvement projects completed in recent years resulted in a significant reduction in the number of occurrences of unplanned downtime. In 2009 we had fewer events causing unplanned downtime than we have experienced in any year since acquiring the Forties field; 64 percent less than our previous best year.

Argentina

Argentina announced several strategic agreements during 2009 that will improve the long-term viability of our investments.

Exploration Activity

On March 30, 2009, Apache announced that the Neuquén Province of Argentina agreed to extend the term of eight federal oil and gas concessions for 10 additional years. Neuquén operations provide about half of Apache s total output in Argentina. The concessions encompass approximately 590,000 acres, including exploratory areas totaling 514,000 acres. In exchange for production that would have reverted to the Province beginning in six years and the right to explore for 10 additional years, Apache paid a bonus of approximately $23 million, increased the provincial royalty to 15 percent from 12 percent and will spend up to $320 million in future work programs over a 19-year period.

Development Activity

During 2009 Apache received technical and commercial approval from the government of Argentina for four Gas Plus projects and technical approval for two more Gas Plus projects designed to encourage new supplies through development of tight sands and unconventional gas reserves. Under the Gas Plus program, Apache has the opportunity to supply 10 MMcf/d from fields in the Neuquén Province at a price of $4.10 per MMBtu beginning January 2010 for an initial one-year term. The Company also has a letter of intent for a contract to supply up to 50 MMcf/d from fields in the Neuquén and Rio Negro Provinces for $5.00 per MMBtu beginning January 2011. The gas supplying the Gas Plus program contracts is required to come from wells

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drilled in the projects approved fields and formations. We believe this type of program, coupled with changing market conditions, point to improving price realizations going forward.

Chile

Exploration Activity

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. Two of the wells reached total depth by year-end 2009, with drilling completed on the third well in early 2010. Currently a completion rig is conducting testing and completion efforts on the three wells. During 2010 the region will invest approximately $25 million to $35 million for drilling and seismic acquisition.

Results of Operations

Oil and Gas Revenues, Production and Prices

	Revenues for the Year Ended December 31,					
	2009		2008		2007	
	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution
Total Oil and Gas Revenues:						
United States	$ 3,050	36%	$ 5,083	41%	$ 4,306	43%
Canada	877	10%	1,651	14%	1,393	14%
North America	3,927	46%	6,734	55%	5,699	57%
Egypt	2,553	30%	2,739	22%	2,012	20%
Australia	363	4%	372	3%	536	6%
North Sea	1,369	16%	2,103	17%	1,399	14%
Argentina	362	4%	380	3%	316	3%
International	4,647	54%	5,594	45%	4,263	43%
Total(1)	$ 8,574	100%	$ 12,328	100%	$ 9,962	100%
Oil Revenues:						
United States	$ 1,922	32%	$ 2,751	34%	$ 2,202	35%
Canada	311	5%	587	7%	468	8%
North America	2,233	37%	3,338	41%	2,670	43%

Egypt	2,063	34%	2,232	27%	1,607	26%
Australia	230	4%	277	3%	401	6%
North Sea	1,356	22%	2,085	26%	1,389	22%
Argentina	207	3%	225	3%	192	3%
International	3,856	63%	4,819	59%	3,589	57%
Total(2)	$ 6,089	100%	$ 8,157	100%	$ 6,259	100%

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	Revenues for the Year Ended December 31,					
	2009		2008		2007	
	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution	$ Value (In millions)	% Contribution
Natural Gas Revenues:						
United States	$ 1,054	44%	$ 2,204	56%	$ 1,977	56%
Canada	547	23%	1,026	26%	892	26%
North America	1,601	67%	3,230	82%	2,869	82%
Egypt	490	21%	507	13%	404	12%
Australia	133	6%	95	2%	134	4%
North Sea	13	0%	18	0%	11	0%
Argentina	132	6%	115	3%	86	2%
International	768	33%	735	18%	635	18%
Total(3)	$ 2,369	100%	$ 3,965	100%	$ 3,504	100%
Natural Gas Liquids (NGL) Revenues:						
United States	$ 74	64%	$ 128	62%	$ 127	64%
Canada	20	17%	38	19%	33	17%
North America	94	81%	166	81%	160	81%
Argentina	22	19%	40	19%	39	19%
Total	$ 116	100%	$ 206	100%	$ 199	100%

(1) Included in oil and gas production revenues for 2009, 2008 and 2007 were a gain of $180.8 million, a loss of $458.7 million and a loss of $32.5 million, respectively, from financial derivative hedging activities.

(2) Included in oil revenues for 2009, 2008 and 2007 were a gain of $45.2 million, a loss of $450.8 million and a loss of $96.6 million, respectively, from financial derivative hedging activities.

(3) Included in natural gas revenues for 2009, 2008 and 2007 were a gain of $135.6 million, a loss of $7.9 million and a gain of $64.1 million, respectively, from financial derivative hedging activities.

	Production and Prices for the Year Ended December 31,				
	2009	Increase (Decrease)	2008	Increase (Decrease)	2007

Oil Volume b/d:					
United States	89,133	−1%	89,797	−1%	90,759
Canada	15,186	−11%	17,154	−9%	18,756
North America	104,319	−2%	106,951	−2%	109,515
Egypt	92,139	+38%	66,753	+10%	60,735
Australia	9,779	+19%	8,249	−40%	13,778
North Sea	60,984	+3%	59,494	+11%	53,632
Argentina	11,505	−7%	12,409	+8%	11,440
International	174,407	+19%	146,905	+5%	139,585
Total(1)	278,726	+10%	253,856	+2%	249,100

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	Production and Prices for the Year Ended December 31,				
	2009	Increase (Decrease)	2008	Increase (Decrease)	2007
Natural Gas Volume Mcf/d:					
United States	666,084	–2%	679,876	–12%	769,596
Canada	359,235	+2%	352,731	–9%	388,211
North America	1,025,319	–1%	1,032,607	–11%	1,157,807
Egypt	362,618	+38%	263,711	+10%	240,777
Australia	183,617	+49%	123,003	–37%	194,928
North Sea	2,703	+3%	2,637	+36%	1,933
Argentina	184,557	–6%	195,651	–3%	200,903
International	733,495	+25%	585,002	–8%	638,541
Total(3)	1,758,814	+9%	1,617,609	–10%	1,796,348
NGL Volume b/d:					
United States	6,136	+3%	5,986	–22%	7,702
Canada	2,089	+1%	2,076	–8%	2,246
North America	8,225	+2%	8,062	–19%	9,948
Argentina	3,241	+12%	2,887	+3%	2,800
Total	11,466	+5%	10,949	–14%	12,748
Average Oil price Per barrel:					
United States	$ 59.06	–29%	$ 83.70	+26%	$ 66.48
Canada	56.16	–40%	93.53	+37%	68.29
North America	58.64	–31%	85.28	+28%	66.79
Egypt	61.34	–33%	91.37	+26%	72.51
Australia	64.42	–30%	91.78	+15%	79.79
North Sea	60.91	–36%	95.76	+35%	70.93
Argentina	49.42	0%	49.46	+8%	45.99
International	60.58	–32%	89.63	+27%	70.45
Total(2)	59.85	–32%	87.80	+28%	68.84
Average Natural Gas price Per Mcf:					
United States	$ 4.34	–51%	$ 8.86	+26%	$ 7.04
Canada	4.17	–47%	7.94	+26%	6.30
North America	4.28	–50%	8.55	+26%	6.79
Egypt	3.70	–30%	5.25	+14%	4.60
Australia	1.99	–5%	2.10	+11%	1.89
North Sea	13.15	–30%	18.78	+25%	15.03
Argentina	1.96	+22%	1.61	+38%	1.17
International	2.87	–16%	3.43	+26%	2.72
Total(4)	3.69	–45%	6.70	+25%	5.34

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	Production and Prices for the Year Ended December 31,				
	2009	Increase (Decrease)	2008	Increase (Decrease)	2007
Average NGL Price Per barrel:					
United States	$ 33.02	–44%	$ 58.62	+30%	$ 45.24
Canada	25.54	–48%	49.33	+22%	40.55
North America	31.12	–45%	56.23	+27%	44.18
Argentina	18.76	–50%	37.83	0%	37.78
Total	27.63	–46%	51.38	+20%	42.78

(1) Approximately 10 percent of 2009 oil production was subject to financial derivative hedges, compared to 19 percent in 2008 and 17 percent in 2007.

(2) Reflects per-barrel increase of $.44 in 2009 and reductions of $4.85 in 2008 and $1.06 in 2007 from financial derivative hedging activities.

(3) Approximately nine percent of 2009 gas production was subject to financial derivative hedges, compared to 20 percent in 2008 and 17 percent in 2007.

(4) Reflects per-Mcf increase of $.21 in 2009, reduction of $.01 in 2008 and increase of $.10 in 2007 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 our control. Prices we received for our crude oil in 2009 were 32 percent below 2008 with the worldwide economic downturn. Apache uses financial instruments to manage a portion of its exposure to fluctuations in crude oil prices, particularly in North America. In 2009, 10 percent of our oil production was subject to financial derivative hedges, increasing revenues by $45 million. In 2008, 19 percent of our oil production was hedged, reducing oil revenue by $451 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 Asian or Dated Brent benchmark crude oil prices, which typically track at or above NYMEX oil prices. In Argentina, we currently sell our oil in the domestic market. The Argentine government previously imposed 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 its exposure to fluctuations in natural gas prices, primarily in North America. In 2009 nine percent of our gas production was subject to financial derivative hedges, increasing revenues by $136 million. In 2008 20 percent of our gas production was hedged, reducing gas revenue by $8 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.

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Apache primarily sells natural gas into the North American market, where spot prices were cut in half compared to 2008, and various international markets, where our average contracted prices declined just 16 percent from 2008. Our primary markets include:

1) North America, which has a common market and where most of our gas is sold on a monthly or daily basis at either monthly or daily market prices.

2) Egypt, where the majority of our gas is sold to EGPC 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 beginning of 2013. The region averaged $3.70 per Mcf in 2009.

3) Australia, which has a local market with mostly long-term, fixed-price contracts that are periodically adjusted for changes in the local consumer price index. Natural gas discoveries are increasingly dedicated to the LNG market, and supply is tightening for delivery to the domestic market. As a result, recent contracts, including for our Reindeer field, are substantially higher than historical levels.

4) Argentina, where 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 2009 we realized an average price of $1.07 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 2009. Our overall average realized price for 2009 was $1.96 per Mcf, 22 percent higher than 2008 average realized prices and 68 percent higher than 2007 average realized prices.

During 2009 Apache received technical and commercial approval from the government of Argentina for four Gas Plus projects and technical approval for two more Gas Plus projects designed to encourage new supplies through development of tight sands and unconventional gas reserves. Under the Gas Plus program, Apache has the opportunity to supply 10 MMcf/d from fields in the Neuquén Province at a price of $4.10 per MMBtu beginning January 1, 2010 for an initial one-year term. The Company also has a letter of intent for a contract to supply up to 50 MMcf/d from fields in the Neuquén and Rio Negro Provinces for $5.00 per MMbtu beginning January 1, 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 this type of 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

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. Crude oil revenues for 2009 totaled $6.1 billion, $2.1 billion lower than 2008. The decrease was driven by a 32 percent decline in average realized prices (-$2.6 billion), mitigated by the impact of 10 percent production growth (+$528 million).

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 (NEAG) 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.

2008 vs. 2007 Crude oil accounted for 48 percent of our equivalent production and 66 percent of our oil and gas production revenues for 2008, compared to 44 and 63 percent, respectively, for 2007. Crude oil revenues for

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2008 totaled $8.2 billion, increasing $1.9 billion on a 28 percent increase in average realized prices (+$1.7 billion) and a two percent production growth (+$175 million).

Worldwide production was up 4.8 Mb/d, driven by increases in the North Sea and Egypt, which more than offset lower production in Australia, Canada and the U.S. Production in the North Sea was up 5.9 Mb/d (11 percent) on successful drilling and workover programs and a reduction in platform downtime. Egypt s production increased 6.0 Mb/d (10 percent) on higher gross production from wells at El Diyur, Umbarka and East Bahariya and higher cost recovery from accelerated capital spending on a gas plant expansion. Argentine production was up 1.0 Mb/d on increased production from new wells in Tierra del Fuego. Australia s production was down 5.5 Mb/d (40 percent), split between shut-ins following a June 2008 pipeline explosion at the Varanus Island gas processing and transportation hub and natural decline. Canada s daily production was 1.6 Mb/d lower on natural decline and property divestitures, which more than offset drilling and recompletion activity. U.S. production declined 1.0 Mb/d. Production in the Gulf Coast region decreased 2.7 Mb/d; shut-in production related to hurricanes reduced annual production by 6.9 Mb/d, offsetting net production growth from the regions drilling program. The Central region s production increased 1.7 Mb/d, driven by property acquisitions and drilling and recompletion activity.

Natural Gas Revenues

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. Gas revenues for 2009 totaled $2.4 billion, down $1.6 billion from 2008. All of the natural gas revenue decline occurred in North America, as a 25 percent increase in international production more than offset a 16 percent decline in international price realizations.

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. The increased compression in the Northern Gas Pipeline also allowed increased throughput at the nearby Tarek plant and enabled us to begin producing previous discoveries at the Jade and Falcon fields in our Matruh concession. 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.

2008 vs. 2007 Gas accounted for 50 percent of our equivalent production and 32 percent of our oil and gas production revenues for 2008, compared to 53 and 35 percent, respectively, for 2007. Natural gas revenues in 2008 totaled $4.0 billion and were $461 million higher than 2007, reflecting a 25 percent increase in realized natural gas prices (+$887 million), which more than offset 10 percent lower production (-$426 million).

Worldwide production decreased 179 MMcf/d. Australian production was down 72 MMcf/d. Volumes were impacted by production shut-in after an explosion on an export pipeline and resulting fire that damaged our processing facilities. U.S. production was 90 MMcf/d lower. Gulf Coast daily production drove the lower U.S. production, with a decrease of 99 MMcf/d. The region s production was negatively impacted by properties shut-in for hurricanes (55 MMcf/d) and facility, rig and third-party downtime (27 MMcf/d), as well as the impact of a delay in the region s drilling program caused by the hurricanes. Central region production increased 10 MMcf/d on drilling and recompletion activities and from incremental volumes from Permian Basin properties acquired in March 2007. Canada s production decreased 35 MMcf/d on natural decline and property divestitures. Egypt s gas production increased 23 MMcf/d (10 percent) on successful recompletions at our Matruh concession, new wells brought online at the NEAG concession and higher cost recovery from accelerated capital spending on gas plant expansion.

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 either on a boe basis, on an absolute dollar basis or both, depending on relevance. Amounts included in this table and in the discussion below are rounded to millions and may differ slightly from those presented elsewhere in this document.

	Year Ended December 31,			Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
	(In millions)			(Per boe)		
Depreciation, depletion and amortization:						
Oil and gas property and equipment						
Recurring	$ 2,202	$ 2,358	$ 2,208	$ 10.34	$ 12.06	$ 10.78
Additional	2,818	5,334		13.24	27.27	
Other assets	193	158	140	.91	.81	.68
Asset retirement obligation accretion	105	101	96	.49	.52	.47
Lease operating expenses	1,662	1,909	1,653	7.81	9.76	8.07
Gathering and transportation	143	157	137	.67	.80	.67
Taxes other than income	579	985	598	2.72	5.03	2.92
General and administrative expenses	344	289	275	1.62	1.48	1.34
Financing costs, net	242	166	220	1.13	.85	1.07
Total	$ 8,288	$ 11,457	$ 5,327	$ 38.93	$ 58.58	$ 26.00

Depreciation, Depletion and Amortization

The following table details the changes in recurring depreciation, depletion and amortization (DD&A) of oil and gas properties between 2009 and 2007:

	Recurring DD&A (In millions)
2007	$ 2,208
Volume change	(127)
Rate change	277
2008	$ 2,358
Volume change	150
Rate change	(306)
2009	$ 2,202

2009 vs. 2008 Recurring full-cost depletion expense decreased $156 million on an absolute dollar basis: $306 million on lower rate, partially offset by an increase of $150 million from higher production. Our full-cost depletion rate decreased $1.72 to $10.34 per boe. The decrease in rate was driven by a $5.33 billion non-cash write-down of the carrying value of our December 31, 2008, proved property balances in the U.S., U.K. North Sea, Canada and Argentina and a $2.82 billion non-cash write-down of the carrying value of our March 31, 2009, proved oil and gas property balances in the U.S. and Canada. The impact of the write-downs was partially offset by 2009 drilling and finding costs, which exceeded our historical cost basis.

Under the full-cost method of accounting, the Company is required to review the carrying value of its proved oil and gas properties each quarter on a country-by-country basis. Under these rules, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted 10 percent, net of related tax effects. Until December 31, 2009, the rules generally required pricing future net cash flows at the unescalated oil and gas prices in effect at the end of each fiscal quarter. Effective December 31, 2009, estimated future net cash flows is calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month in 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. The rules also generally require the estimation of future costs using costs in effect at the end of each fiscal quarter. Write-downs required by these rules do not impact cash flow from operating activities.

2008 vs. 2007 During 2008, recurring full-cost depletion expense increased $150 million, $277 million on rate, partially offset by $127 million on lower volumes. Our full-cost depletion rate increased $1.28 to $12.06 per boe on drilling and finding costs that exceeded our historical cost basis. Higher industry-wide costs, which also impacted estimates of future development costs, were driven by increased demand for drilling services, a consequence of higher oil and gas prices.

Lease Operating Expenses

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

Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity-price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as labor, boats, helicopters, materials and supplies. Oil, which contributed nearly half of our production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties and in areas with remote plants and facilities. All production in Australia and the North Sea and nearly 90 percent from the U.S. Gulf Coast region comes from offshore properties. Workovers accelerate production; hence, activity generally increases with higher commodity prices. Foreign exchange rate fluctuations generally impact the Company s LOE, with a weakening U.S. dollar adding to per-unit costs and a strengthening U.S. dollar lowering per-unit costs in our international regions.

2009 vs. 2008 Our 2009 LOE decreased $247 million from 2008. LOE per boe was down 20 percent: 13 percent on lower cost and seven percent on higher production. The rate was impacted by the items below:

	Per boe
2008 LOE	$ 9.76
Higher production	(.68)
Workover costs	(.36)
Foreign exchange rate impact	(.33)
Power and fuel	(.32)
Labor and pumper costs	(.10)
Hurricane repairs	(.10)
Other	(.06)
2009 LOE	$ 7.81

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2008 vs. 2007 Our 2008 LOE increased $256 million from 2007. LOE per boe was up 21 percent: 15 percent on higher cost and six percent on lower production. The rate was impacted by the items below:

	Per boe
2007 LOE	$ 8.07
Lower production	.45
Higher operating costs, including power and labor	.33
Workover costs	.29
Non-recurring repairs and maintenance	.07
Hurricane repairs	.07
Varanus Island repair costs	.03
Other	.45
2008 LOE	$ 9.76

Gathering and Transportation

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

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

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

	For the Year Ended December 31,		
	2009	2008	2007
	(In millions)		
U.S.	$ 35	$ 39	$ 38
Canada	53	64	54
North Sea	26	28	27
Egypt	24	21	15
Argentina	5	5	3
Total Gathering and Transportation	$ 143	$ 157	$ 137

Total Gathering and Transportation per boe	$ .67	$ .80	$ .67

2009 vs. 2008 Gathering and transportation costs decreased $14 million from 2008. On a per unit basis, gathering and transportation costs were down 16 percent: nine percent on lower costs and seven percent on higher production.

The decreases in the U.S. and Canada resulted from a decrease in both the volumes transported under arrangements where we pay costs directly to third-parties and in rates. North Sea costs were down on foreign exchange rates. Egypt costs increased as a result of retroactive terminal fees claimed by EGPC, partially offset by a decrease in export cargoes as more crude oil was purchased by EGPC for domestic use in the latter part of 2009.

2008 vs. 2007 Gathering and transportation costs for 2008 increased $20 million from 2007. On a per unit basis, gathering and transportation costs were up 19 percent: 15 percent on higher costs and four percent on lower

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production. The increase was driven primarily by higher transportation tariffs in Canada and an increase in Egyptian export volumes.

Taxes Other Than Income

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

	For the Year Ended December 31,		
	2009	2008	2007
		(In millions)	
U.K. PRT	$ 383	$ 695	$ 346
Severance taxes	88	168	142
Ad valorem taxes	55	71	56
Other taxes	53	51	54
Total Taxes other than income	$ 579	$ 985	$ 598
Total Taxes other than income per boe	$ 2.72	$ 5.03	$ 2.92

2009 vs. 2008 Taxes other than income were $406 million lower than 2008. On a per unit basis, they decreased 46 percent: 41 percent on lower costs and five percent on higher production.

U.K. PRT was $312 million less than 2008 on a 43 percent decrease in net profits, driven by lower oil revenues and lower operating and capital costs. The decrease in severance taxes resulted from lower taxable revenues in the U.S., consistent with the lower realized oil and natural gas prices relative to the prior year. The $16 million decrease in ad valorem taxes resulted from lower taxable valuations associated with decreases in oil and natural gas prices.

2008 vs. 2007 Taxes other than income for 2008 were $387 million higher than 2007. On a per unit basis, they increased 72 percent: 65 percent on higher costs and seven percent on lower production.

U.K. PRT was $349 million more than 2007 on a 98 percent increase in net profits, driven by higher oil revenues. The increase in severance taxes resulted from higher taxable revenues in the U.S., consistent with the higher realized oil and natural gas prices in the first nine months of the year. The $15 million increase in ad valorem taxes resulted from higher taxable valuations associated with increases in oil and natural gas prices at the time the taxes were assessed and a full year of taxes on the Permian Basin properties acquired in the first quarter of 2007.

General and Administrative Expenses

2009 vs. 2008 General and administrative (G&A) expenses were $55 million higher in 2009 than in 2008. On a per boe basis, G&A expenses increased nine percent: 19 percent on higher costs, offset by a 10 percent reduction on higher volumes. The increase was driven by $39 million of nonrecurring charges related to the retirement of our founder and former chairman and employee separation costs related to a 2009 workforce reduction. Stock-based compensation expense increased $34 million on the impact of higher stock appreciation relative to 2008 and new awards issued in 2009. Insurance premiums were up $9 million. These increases were partially offset by net reductions in other corporate expenses of $27 million.

2008 vs. 2007 G&A expenses were $14 million higher in 2008 compared to 2007. On a per boe basis, G&A expenses increased 10 percent: five percent on higher costs and five percent on lower volumes. The cost increase was driven by higher legal fees, especially in our international operations, increased incentive compensation expenses and miscellaneous higher costs in several departments, partially offset by a decrease in stock-based compensation expenses related to cash-settled stock appreciation rights.

Financing Costs, Net

Financing costs incurred during the periods noted are composed of the following:

	For the Year Ended December 31,		
	2009	2008	2007
		(In millions)	
Interest expense	$ 309	$ 280	$ 308
Amortization of deferred loan costs	6	4	3
Capitalized interest	(61)	(94)	(75)
Interest Income	(12)	(24)	(16)
Total Financing costs	$ 242	$ 166	$ 220
Financing costs per boe	$ 1.13	$ .85	$ 1.07

2009 vs. 2008 Financing costs, net increased $76 million from 2008. On a per unit basis, they increased 33 percent: 46 percent on higher costs, offset by a 13 percent reduction related to production growth.

The increase in cost is primarily the result of a $29 million increase in interest expense related to higher average outstanding debt balances, a $33 million reduction in capitalized interest related to lower unproved property balances and completion of several long-term construction projects, and a $12 million decrease in interest income on a lower average cash balance and lower interest rates.

2008 vs. 2007 Financing costs, net for 2008 decreased $54 million from 2007. On a per unit basis, they decreased 21 percent: 25 percent on lower costs and four percent on production growth.

Interest expense was down $28 million on lower average outstanding debt balances. Capitalized interest was up primarily because of expenditures associated with long-term construction projects under development.

Provision for Income Taxes

2009 vs. 2008 There were no significant changes in statutory tax rates in the major jurisdictions in which the Company operates during 2009.

The provision for income taxes totaled $611 million in 2009 compared to $220 million in 2008. Total taxes and the effective rates for each period were skewed by the magnitude of the taxes related to the 2009 and 2008 full-cost write-downs, the effect of currency exchange rates on our foreign deferred tax liabilities and other net tax settlements. Excluding these items, the 2009 and 2008 effective tax rates were comparable at 39.83 percent and 39.58 percent, respectively.

2008 vs. 2007 There were no significant changes in statutory tax rates in the major jurisdictions in which the Company operates during 2008. In 2007 we saw a significant reduction to deferred income taxes resulting from Canadian tax rate reductions.

The provision for income taxes decreased $1.6 billion from 2007 to $220 million, as income before taxes decreased 80 percent as a result of the $5.3 billion in additional DD&A recorded in conjunction with the ceiling test write-down. The effective income tax rate for the year was 23.6 percent compared to 39.8 percent in 2007. The 2008 effective rate was impacted by the magnitude of the taxes related to the write-down, non-cash benefits related to the effect of the strengthening U.S. dollar on our foreign deferred tax liabilities and other net tax settlements. The 2007 effective rate was impacted by a non-cash charge related to the effect of the weakening U.S. dollar on our foreign deferred tax liabilities. Partially offsetting this charge was an out of period benefit from Canadian federal tax rate reductions enacted in the second and fourth quarters of 2007. Excluding these items, the 2008 effective rate would have been comparable to the 2007 effective rate.

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Non-GAAP Measures

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

Adjusted Earnings

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

	For the Year Ended December 31, 2009	2008
	(In thousands, except per share data)	
Income (Loss) Attributable to Common Stock (GAAP)	$ (291,692)	$ 706,274
Adjustments:		
Foreign currency fluctuation impact on deferred tax expense	197,724	(397,454)
Additional depletion, net of tax(1)	1,981,398	3,647,745
Out-of-period tax adjustments		(173,795)
Adjusted Earnings (Non-GAAP)	$ 1,887,430	$ 3,782,770
Adjusted Earnings Per Share (Non-GAAP)		
Basic	$ 5.62	$ 11.31
Diluted	$ 5.59	$ 11.22
Average Number of Common Shares		
Basic	335,852	334,351
Diluted	337,737	337,191

(1) Additional depletion (non-cash write-down of the carrying value of proved property) recorded in 2009 was $2,818,161 pre-tax, for which a deferred tax benefit of $836,763 was recognized. Also, additional depletion was recorded in 2008 totaling $5,333,821 pre-tax, for which a deferred tax benefit of $1,686,076 was recognized. The tax effect of write-down of the carrying value of proved property (additional depletion) in both 2009 and 2008 were calculated utilizing the statutory rates in effect in each country where a write-down occurred.

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Significant Acquisitions and Divestitures

2009 Activity

During the second quarter of 2009 Apache announced the acquisition of nine Permian Basin oil and gas fields with then current net production of 3,500 barrels of oil equivalent per day from Marathon Oil Corporation for $187.4 million, subject to normal post-closing adjustments. Estimated reserves acquired in connection with the acquisition totaled 19.5 MMboe. These long-lived fields fit well with Apache s existing properties in the Permian Basin, particularly in Lea County, N.M., and will provide the Company many years of drilling opportunities. The effective date of the transaction was January 1, 2009.

2008 Activity

There was no major acquisition activity during 2008; however, the Company completed several divestiture transactions. On January 29, 2008, the Company completed the sale of its interest in Ship Shoal blocks 349 and 359 on the outer continental shelf of the Gulf of Mexico to W&T Offshore, Inc. for $116 million. On January 31, 2008, the Company completed the sale of non-strategic oil and gas properties in the Permian Basin of West Texas to Vanguard Permian, LLC for $78 million. On April 2, 2008, the Company completed the sale of non-strategic Canadian properties to Central Global Resources for C$112 million. These divestitures were subject to normal post-closing adjustments.

2007 Activity

U.S. Gulf Coast Farm-in On September 6, 2007, Apache entered into an Exploration Agreement with various EnerVest Partnerships (EVP) for an initial term of four years whereby Apache committed to spend $30 million in qualified expenditures to explore, drill, produce and market hydrocarbons from specified undeveloped formations across 400,000 net acres in Central and East Texas. As of December 31, 2008, Apache had fulfilled the $30 million commitment.

U.S. Permian Basin On March 29, 2007, the Company closed its acquisition of controlling interest in 28 oil and gas fields in the Permian Basin of West Texas from Anadarko for $1 billion. Apache estimates that these fields had proved reserves of 57 million barrels (MMbbls) of liquid hydrocarbons and 78 billion cubic feet (Bcf) of natural gas as of year-end 2006. The Company funded the acquisition with debt. Apache and Anadarko entered into a joint-venture arrangement to effect the transaction. The Company entered into cash flow hedges for a portion of the crude oil and natural gas production.

Capital Resources and Liquidity

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

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

We may also elect to utilize available committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the occasional sale of nonstrategic assets for all other liquidity and capital resource needs. Apache s ability to access the debt and equity capital markets is supported by its investment-grade credit ratings.

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

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

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

Sources and Uses of Cash

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

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 4,224	$ 7,065	$ 5,677
Sales of short-term investments	792		
Sales of property and equipment	2	308	67
Project financing draw-downs	250	100	
Fixed-rate debt borrowings		796	1,992
Common stock activity	29	32	30
Treasury stock activity	6	4	14
Other	29	40	26
	5,332	8,345	7,806
Uses of Cash and Cash Equivalents:			
Capital expenditures(1)	3,631	5,823	4,782
Purchase of short-term investments		792	
Acquisitions	310	150	1,025
Net commercial paper and bank loan repayments	2	200	1,412
Payments on fixed-rate notes	100		173
Redemption of preferred stock	98		
Dividends	209	239	205
Other	115	85	224
	4,465	7,289	7,821
Increase (decrease) in cash and cash equivalents	$ 867	$ 1,056	$ (15)

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

Net Cash Provided by Operating Activities Net cash provided by operating activities (operating cash flows or cash flows) is our primary source of capital and liquidity and is impacted, both in the short-term and the long-term, by highly volatile oil and natural gas prices.

Our average natural gas price realizations fluctuated throughout 2009, dipping from a high of $4.31 per Mcf in January to a low of $3.29 in September before increasing to $4.16 in December. Average realized prices in 2009 for natural gas fell 45 percent to $3.69 per Mcf. Our average crude oil realizations saw a gradual increase from a low of $40.24 per barrel in January 2009, peaking in November at $75.09, before falling back to $71.13 in December. Crude oil prices averaged $59.85 per barrel, down 32 percent from 2008.

In order to manage the variability in cash flows, we increased our commodity hedge positions during the third and fourth quarters of 2009. At the end of 2009, we had hedged an average of just over 450,000 MMBtu per day of our projected 2010 North American natural gas production. The volumes were primarily hedged using fixed-price swaps at an average price of approximately $5.65 per MMBtu. For perspective, the natural gas hedges represent 41 percent of fourth-quarter 2009 North America daily gas production; 24 percent worldwide. We also had an average of just over 35,000 b/d of oil production hedged for 2010. Crude oil production was primarily hedged using collars that had average floor and ceiling prices of approximately $65.00 and $80.80 per barrel, respectively. For perspective, the oil hedges represent 13 percent of fourth-quarter 2009 worldwide daily oil production. For additional information regarding our derivative contracts, please see Note 3 Derivative Instruments and Hedging

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Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. For quantitative and qualitative information regarding our use of derivatives to manage commodity price risk, please see Commodity Risk in Part II, Item 7A of this Form 10-K.

The factors affecting operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation (ARO) accretion and deferred income tax expense.

For 2009 operating cash flows totaled $4.2 billion, down $2.8 billion from 2008. The primary driver of the reduction was a $3.8 billion decrease in oil and gas revenues, with the impact of lower commodity prices more than offsetting a nine percent increase in equivalent daily production. Also negatively impacting operating cash flows was the change in working capital from year-end 2008 to year-end 2009. These items were partially offset by the impact of a decline in cash-based expenses and lower current taxes.

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

Short-term Investments We occasionally invest in highly-liquid, short-term investments until funds are needed to further supplement our operating cash flows. At December 31, 2008, we had $792 million invested in U.S. Treasury securities with original maturities greater than three months but less than one year. These securities matured on April 2, 2009. None were held at December 31, 2009.

Project Financing Draw-downs One of the Company s Australian subsidiaries has a secured revolving syndicated credit facility for its Van Gogh and Pyrenees oil developments offshore Western Australia. The outstanding balance under the facility increased $250 million during the year to $350 million at December 31, 2009. For a more detailed discussion of this facility and information regarding our available committed borrowing capacity, please see Liquidity in this Item 7.

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

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

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

	Year Ended December 31, 2009	2008	2007
		(In millions)	
Exploration and Development:			
United States	$ 929	$ 2,183	$ 1,631
Canada	412	705	651
North America	1,341	2,888	2,282
Egypt	676	853	605
Australia	602	880	516
North Sea	375	459	538
Argentina	140	318	287
Chile	11	27	
International	1,804	2,537	1,946
Worldwide Exploration and Development Costs	3,145	5,425	4,228
Gathering, Transmission and Processing Facilities:			
Canada	83	29	24
Egypt	151	571	422
Australia	69	54	14
Argentina	2	5	13
Total Gathering, Transmission and Processing Facility Cost	305	659	473
Asset Retirement Costs	293	514	439
Capitalized Interest	61	94	76
Capital Expenditures, excluding Acquisitions	3,804	6,692	5,216
Acquisitions	310	150	1,025
Total Capital Expenditures	$ 4,114	$ 6,842	$ 6,241

Exploration and Development (E&D) As planned, our 2009 worldwide exploration and development (E&D) expenditures were 42 percent lower than 2008. We reduced 2009 expenditures in response to the precipitous decline in commodity prices and the uncertainties surrounding the financial crisis in late 2008 and early in 2009, seeking to keep capital spending in line with 2009 operating cash flows. Consequently, our E&D investments in all countries were down. E&D spending in North America was 54 percent less than the prior year as we lowered activity and concentrated on identifying drilling opportunities and building inventory. Investments in Egypt were $177 million lower than the prior year as we scaled back drilling activity in the Western Desert. However, Egypt s percentage of worldwide E&D spending rose to 21 percent, up from 16 percent. Australia s E&D expenditures were 32 percent below 2008 on lower drilling activity and lower investments in platforms and production facilities. North Sea E&D expenditures were $84 million lower as their investment requirements dropped following completion of several platform upgrades in 2008.

Acquisitions We completed $310 million of acquisitions in 2009 compared to $150 million in 2008. Acquisition capital expenditures occur as attractive opportunities arise and, therefore, vary from year to year.

Asset Retirement Costs In 2009 we recorded $293 million of additional future asset retirement costs associated with continued worldwide drilling programs, acquisition activity and further assessment of Hurricane Ike damages.

Gathering, Transmission and Processing Facilities (GTP) We invested $305 million in GTP facilities in 2009 compared to $659 million in 2008. In Egypt we invested $151 million in gas processing facilities to alleviate capacity constraints, which were restricting production. We also invested $69 million in Australia on GTP projects currently in process. In Canada, we invested $83 million in processing plants.

2010 Outlook In order to preserve our strong balance sheet and financial flexibility, we plan to keep E&D capital spending generally in line with 2010 operating cash flows. While funds have been committed for certain 2010 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 will closely monitor commodity prices, service cost levels and predicted operating cash and will adjust our exploration and development budgets accordingly. However, with $2.0 billion of cash on our balance sheet, we have the flexibility to utilize this surplus for acquisitions or drilling and development projects that might otherwise not progress. Because we typically revise our exploration and development capital budgets throughout the year depending on prices, projecting future expenditures is somewhat difficult. Our current 2010 capital budget includes exploration and development capital of approximately $6.0 to $6.5 billion, including GTP. We generally do not project capital estimates for acquisitions because they are specific discrete events whose occurrence and timing is unpredictable. Any acquisitions could be funded from operating cash flow, credit facilities, new equity, or a combination thereof.

Payments on Fixed-rate Notes The $100 million Apache Finance Pty Ltd (Apache Finance Australia) 7.0-percent notes matured on March 15, 2009. The notes were repaid using existing cash balances.

Redemption of Preferred Stock The Company redeemed with cash all of its 5.68-percent Cumulative Series B Preferred Stock on December 30, 2009. The 100,000 outstanding shares of Series B Preferred Stock were redeemed at a redemption price of $1,000 per share, plus $9.47 in accrued and unpaid dividends.

Dividends The Company has paid cash dividends on its common stock for 45 consecutive years through 2009. Future dividend payments will depend on the Company s level of earnings, financial requirements and other relevant factors. Common stock dividends paid during 2009 totaled $201 million, compared with $234 million in 2008 and $199 million in 2007. The 2008 period included a special non-recurring cash dividend of 10 cents per common share paid on March 18, 2008.

As discussed above, on December 30, 2009, the Company redeemed with cash all of its 5.68-percent Cumulative Series B Preferred Stock. As a result, the Company paid a total of $6.6 million of dividends, which includes two months of dividends accelerated because of the redemption. Also, in conjunction with the redemption of these shares, the Company was required to classify $1.6 million of the redemption amount ($100 million face value less $98.4 million carrying value) as preferred stock dividends. During 2008 and 2007 the Company paid $5.7 million of dividends each year. For additional information, please see Note 7 Capital Stock in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Liquidity

	At December 31,	
(Millions of Dollars Except as Indicated)	**2009**	**2008**
Cash and cash equivalents	$ 2,048	$ 1,181
Short-term investments		792
Restricted cash		14
Total debt	5,067	4,922
Shareholders equity	15,779	16,509
Available committed borrowing capacity	2,300	2,550

Floating-rate debt/total debt	7%	2%
Percent of total debt to capitalization	24%	23%

Our liquidity and financial position have not been materially affected by the ongoing turmoil in the credit markets. We believe that losses from non-performance are unlikely to occur; however, we are not able to predict sudden changes in the creditworthiness of the financial institutions with which we do business. Twenty-six of 27 banks with lending commitments to the Company have credit ratings of at least single-A, which in some cases is based on government support. There is no assurance that the financial condition of these banks will not deteriorate or that the government guarantee will be maintained. We closely monitor the ratings of the 27 banks in our bank group. Having a large bank group allows the Company to mitigate the impact of any bank s failure to honor its lending commitment.

Cash and Cash Equivalents We had $2.05 billion in cash and cash equivalents at December 31, 2009. At December 31, 2009, $1.4 billion of cash was held by foreign subsidiaries and approximately $650 million was held by Apache Corporation and U.S. subsidiaries. The cash held by foreign subsidiaries is subject to additional U.S. income taxes if repatriated. Almost all of the cash is denominated in U.S. dollars and, at times, is invested in highly liquid, investment-grade securities, with maturities of three months or less at the time of purchase. We intend to use cash from our international subsidiaries to fund international projects. We held $1.2 billion in cash and cash equivalents at December 31, 2008.

Short-term Investments We occasionally invest in highly-liquid, short-term investments. As needed, we may reduce such short-term investment balances to further supplement our operating cash flows. As of December 31, 2009, Apache held no short-term investments. At December 31, 2008, the Company had $792 million invested in obligations of the U.S. government with original maturities greater than three months but less than a year.

Restricted Cash The Company classifies cash balances as restricted cash when it is restricted as to withdrawal or usage. As of December 31, 2008, we had approximately $14 million of property divestiture proceeds classified as restricted cash and held in escrow available for use in a like-kind exchange under Section 1031 of the U.S. federal income tax code. The Company expected to use these funds to purchase noncurrent assets. Accordingly, the restricted cash was classified as long-term at year-end. Subsequent to year-end 2008 the time limits pursuant to Section 1031 expired and the funds were transferred to cash. As of December 31, 2009, no cash balances were classified as restricted cash.

Debt At December 31, 2009, outstanding debt, which consisted of notes, debentures, uncommitted bank lines and project financing, totaled $5.1 billion. Current debt includes $110 million of loans under the Apache PVG Pty Ltd credit facility due in 2010 and $7 million borrowed under uncommitted overdraft lines in Argentina. We have $100 million of debt maturing in 2011, $480 million maturing in 2012, $945 million maturing in 2013, $15 million maturing in 2014, and the remaining $3.4 billion maturing intermittently in years 2015 through 2096.

Debt-to-Capitalization Ratio The Company s debt-to-capitalization ratio as of December 31, 2009 was 24 percent.

Available Credit Facilities As of December 31, 2009, the Company had unsecured committed revolving syndicated bank credit facilities totaling $2.3 billion, which mature in May 2013. The facilities consist of a $1.5 billion facility and a $450 million facility in the U.S., a $200 million facility in Australia and a $150 million facility in Canada. The $1.5 billion and the $450 million credit facilities (U.S. credit facilities) also allow the company to borrow under competitive auctions. The U.S. credit facilities are used to support Apache s commercial paper program.

The financial covenants of the credit facilities require the Company to maintain a debt-to-capitalization ratio of not greater than 60 percent at the end of any fiscal quarter. The negative covenants include restrictions on the Company s ability to create liens and security interests on our assets, with exceptions for liens typically arising in the oil and gas industry, purchase money liens and liens arising as a matter of law, such as tax and mechanics liens. The Company may incur liens on assets located in the U.S. and Canada of up to five percent of the Company s consolidated assets, or approximately $1.4 billion as of December 31, 2009. There are no restrictions on incurring liens in countries other than U.S. and Canada. There are also restrictions on Apache s ability to merge with another entity, unless the Company is the surviving entity, and a restriction on our ability to guarantee debt of entities not within our consolidated group.

There are no clauses in the facilities that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes (MAC clauses). The credit facility agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, the agreements allow the lenders to accelerate payments and terminate lending commitments if Apache Corporation, or any of its U.S. or Canadian subsidiaries, defaults on any direct payment obligation in excess of $100 million or has any unpaid, nonappealable judgment against it in excess of $100 million. The Company was in compliance with the terms of the credit facilities as of December 31, 2009.

At the Company s option, the interest rate for the facilities is based on (i) the greater of (a) the JP Morgan Chase Bank prime rate or (b) the federal funds rate plus one-half of one percent or (ii) the London Inter-bank Offered Rate (LIBOR) plus a margin determined by the Company s senior long-term debt rating.

At December 31, 2009, the margin over LIBOR for committed loans was .19 percent on the $1.5 billion facility and .23 percent on the other three facilities. If the total amount of the loans borrowed under the $1.5 billion facility equals or exceeds 50 percent of the total facility commitments, then an additional .05 percent will be added to the margins over LIBOR. If the total amount of the loans borrowed under all of the other three facilities equals or exceeds 50 percent of the total facility commitments, then an additional .10 percent will be added to the margins over LIBOR. The Company also pays quarterly facility fees of .06 percent on the total amount of the $1.5 billion facility and .07 percent on the total amount of the other three facilities. The facility fees vary based upon the Company s senior long-term debt rating.

One of the Company s Australian subsidiaries has a secured revolving syndicated credit facility for its Van Gogh and Pyrenees oil developments offshore Western Australia. The facility provides for total commitments of up to $350 million, with availability determined by a borrowing base formula. The borrowing base was set at $350 million and will be redetermined after the fields commence production in the first half of 2010 and certain tests have been met, and semi-annually thereafter. The facility is secured by certain assets associated with the Van Gogh and Pyrenees oil developments, including the shares of stock of the Company s subsidiary holding the assets. The Company agreed to guarantee the credit facility until project completion occurs pursuant to terms of the facility, which is expected in the fourth quarter of 2010. In the event project completion does not occur by December 31, 2010, pursuant to terms of the facility the lenders may require repayment of outstanding amounts in the first quarter of 2011. Interest is based on LIBOR, which may be subject to change under certain market disruption conditions, plus a margin of 1.00 percent pre-completion and 1.75 percent post-completion. The pre-completion margin increases to 1.125 percent in the event the Company s ratings are downgraded to BBB+ or below by at least two major rating agencies. As of December 31, 2009 and 2008, there was $350 million and $100 million, respectively, outstanding under the facility. The commitments under the facility will be reduced by scheduled increments every six months beginning June 30, 2010, with final maturity on March 31, 2014. The outstanding amount under this facility must not exceed $300 million on June 30, 2010 and $240 million on December 31, 2010. Accordingly, $50 million and $60 million of the current balance will be repaid by June 30, 2010 and December 31, 2010, respectively and has been classified as current debt at December 31, 2009.

Commercial Paper Program The Company has available a $1.95 billion commercial paper program, which generally enables Apache to borrow funds for up to 270 days at competitive interest rates. If the Company is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, the Company s U.S. credit facilities are available as a 100-percent backstop. The commercial paper program is fully supported by available borrowing capacity under U.S. committed credit facilities, which expire in 2013. As of December 31, 2009 and 2008, the Company had no outstanding commercial paper.

Credit Ratings 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, reserve mix and commodity pricing levels could also be considered by the rating agencies. Apache s senior unsecured long-term debt is currently rated A3 by Moody s, A- by Standard & Poor s and A- by Fitch. The Company has received short-term debt ratings for its commercial paper program of P-2 from Moody s, A-2 from Standard & Poor s and F2 from Fitch. In September 2009 Fitch downgraded Apache s senior unsecured long-term debt and short-term debt from A and F1 to A- and F2, respectively. The current outlook at all three rating agencies is stable. A further 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 in certain circumstances.

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Contractual Obligations

We are subject to various financial obligations and commitments in the normal course of operations. These contractual obligations represent known future cash payments that we are required to make and relate primarily to long-term debt, operating leases, pipeline transportation commitments and international commitments. The Company expects to fund these contractual obligations with cash generated from operating activities.

The following table summarizes the Company s contractual obligations as of December 31, 2009. For additional information regarding these obligations, please see Note 5 Debt and Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Contractual Obligations	Note Reference	Total	2010	2011-2013	2014-2015	2016 & Beyond
			(In millions)			
Debt	Note 5	$ 5,088	$ 117	$ 1,525	$ 365	$ 3,081
Interest payments	Note 5	4,812	296	830	433	3,253
Drilling rig commitments	Note 8	481	419	62		
Purchase obligations	Note 8	611	382	229		
E&D commitments	Note 8	446	125	254	67	
Firm transportation agreements	Note 8	314	50	131	80	53
Office and related equipment	Note 8	124	26	61	13	24
Oil and gas operations equipment	Note 8	468	82	123	52	211
Other	Note 8	5	5			
Total Contractual Obligations(a)(b)(c)(d)		$ 12,349	$ 1,502	$ 3,215	$ 1,010	$ 6,622

(a) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1.8 billion. For additional information regarding asset retirement obligation, please see Note 4 Asset Retirement Obligation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(b) This table does not include the Company s $266 million net liability for outstanding derivative instruments valued as of December 31, 2009. For additional information regarding derivative instruments, 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.

(c) This table does not include the Company s pension or postretirement benefit obligations. For additional information regarding pension and postretirement benefit obligations, please see Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(d) This table does not include the Company s tax reserves. For additional information regarding tax reserves, please see Note 6 Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Apache is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. Apache s management feels that it has adequately reserved for its contingent obligations, including approximately \$27 million for environmental remediation and approximately \$20 million for various contingent legal liabilities. For a detailed discussion of the Company s environmental and legal contingencies, please see Note 8 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

The Company also accrued approximately \$63 million as of December 31, 2009, for an insurance contingency as a member of Oil Insurance Limited (OIL). This insurance co-op insures specific property, pollution liability and other catastrophic risks of the Company. As part of its membership, the Company is contractually committed to pay a withdrawal premium if we elect to withdraw from OIL. Apache does not anticipate withdrawal from the insurance pool; however, the potential withdrawal premium is calculated annually based on past losses and the nature of our asset base. The liability reflecting this potential charge has been fully accrued.

Off-Balance Sheet Arrangements

Apache does not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions.

Critical Accounting Policies and Estimates

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

Reserve Estimates

In January 2009, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting (Release 33-8995), amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. 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. In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which amends Accounting Standards Codification (ASC) Topic 932, Extractive Industries Oil and Gas to align the guidance with the changes made by the SEC. The Company adopted Release 33-8995 and the amendments to ASC Topic 932 resulting from ASU 2010-03 (collectively, the Modernization Rules) effective December 31, 2009.

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.

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

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

Reserves as of December 31, 2009 were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month in 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. Reserves as of December 31, 2008 and 2007 were estimated using prices in effect at the end of those years, in accordance with SEC guidance in effect prior to the issuance of the Modernization Rules.

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

Asset Retirement Obligation (ARO)

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

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO is recorded at fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Income Taxes

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

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

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

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

The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Risk

The Company s revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas and NGLs, which have historically been very volatile due to unpredictable events such as economical growth or retraction, weather and climate. Our average monthly crude oil realizations saw a gradual increase from a low of $40.24 per barrel in January 2009, peaking in November at $75.09, before falling back to $71.13 in December. In 2009 crude oil prices averaged $59.85 per barrel down 32 percent from 2008. Our average monthly natural gas price realizations fluctuated throughout 2009, dipping from a high of $4.31 per Mcf in January to a low of $3.29 in September before increasing to $4.16 in December. Average realized prices in 2009 for natural gas fell 45 percent to $3.69 per Mcf.

For 2009 approximately nine percent of our natural gas production was subject to financial derivative hedges. In the third and fourth quarters of 2009, we entered into additional hedges on our 2010 projected North American gas production. For perspective, these 2010 hedges represent approximately 24 percent of our fourth-quarter 2009 worldwide daily gas volumes and approximately 41 percent of our fourth-quarter 2009 North American daily gas production.

For 2009 approximately 10 percent of our crude oil production was subject to financial derivative hedges. In the third and fourth quarters of 2009, we entered into additional crude oil hedges on our 2010 projected production. For perspective, these 2010 hedges represent approximately 13 percent of our fourth-quarter 2009 worldwide daily oil volumes.

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

On December 31, 2009, the Company had open natural gas derivative hedges in an asset position with a fair value of $56 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $128 million, while a 10 percent decrease in prices would increase the fair value by approximately $127 million. The Company also had open oil derivatives in a liability position with a fair value of $322 million. A 10 percent increase in oil prices would increase the liability by approximately $202 million, while a 10 percent decrease in prices would decrease the liability by approximately $190 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2009. For notional volumes and terms associated with the Company s derivative contracts, please see Note 3 Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Apache conducts its risk management activities for its commodities under the controls and governance of its risk management policy. The Risk Management Committee, comprising the President (principal financial officer), General Counsel, Treasurer and other key members of Apache s management, approve and oversee these controls, which have been implemented by designated members of the treasury department. The treasury and accounting departments also provide separate checks and reviews on the results of hedging activities. Controls for our commodity risk management activities include limits on credit, limits on volume, segregation of duties, delegation of authority and a number of other policy and procedural controls.

Interest Rate Risk

On December 31, 2009, the Company s debt with fixed interest rates represented approximately 93 percent of total debt. As a result, the interest expense on approximately seven percent of Apache s debt will fluctuate based on short-term interest rates. A 10 percent change in floating interest rates on year-end floating debt balances would change annual interest expense by approximately $537,000.

Foreign Currency Risk

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

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of Other under Revenues and Other or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company s provision for income tax expense on the Statement of Consolidated Operations. A 10 percent strengthening or weakening of the Australian dollar, Canadian dollar, British pound, Egyptian pound or Argentine peso as of December 31, 2009, would result in a foreign currency net loss or gain, respectively, of approximately $95 million.

Forward-Looking Statements and Risk

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2009, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, plan, believe, or continue or similar terminology. believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- the market prices of oil, natural gas, NGLs and other products or services;
- our commodity hedging arrangements;
- the supply and demand for oil, natural gas, NGLs and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- currency exchange rates;
- weather conditions;
- inflation rates;

the availability of goods and services;

legislative or regulatory changes;

terrorism;

occurrence of property acquisitions or divestitures;

the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks; and other factors disclosed under Items 1 and 2 Business and Properties Estimated Proved Reserves and Future Net Cash Flows, Item 1A Risk Factors, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this Form 10-K.

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

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

The financial statements and supplementary financial information required to be filed under this item are presented on pages F-1 through F-64 in Part IV, Item 15 of this Form 10-K and are incorporated herein by reference.

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

The financial statements for the fiscal years ended December 31, 2009, 2008 and 2007, included in this report, have been audited by Ernst & Young LLP, registered public accounting firm, as stated in their audit report appearing herein.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

G. Steven Farris, the Company s Chairman and Chief Executive Officer, in his capacity as principal executive officer, and Roger B. Plank, the Company s President, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2009, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company s disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure. We also made no changes in internal controls over financial reporting during the quarter ending December 31, 2009, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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

Management s Report on Internal Control Over Financial Reporting

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

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

Changes in Internal Control Over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2009, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT*

The information set forth under the captions Nominees for Election as Directors, Continuing Directors, Executive Officers of the Company, and Securities Ownership and Principal Holders in the proxy statement relating to the Company s 2010 annual meeting of stockholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

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

ITEM 11. *EXECUTIVE COMPENSATION*

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

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

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

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

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

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

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

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K*

(a) Documents included in this report:

1. *Financial Statements*

2. *Financial Statement Schedules*

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

3. *Exhibits*

Exhibit No.	Description
*3.1	Restated Certificate of Incorporation of Registrant, dated February 23, 2010, as filed with the Secretary of State of Delaware on February 23, 2010.
3.2	Bylaws of Registrant, as amended August 6, 2009 (incorporated by reference to Exhibit 3.2 to Registrant s Quarterly Report on Form 10-K for quarter ended June 30, 2009, SEC File No. 001-4300).
4.1	Form of Certificate for Registrant s Common Stock (incorporated by reference to Exhibit 4.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, SEC File No. 001-4300).
4.2	Rights Agreement, dated January 31, 1996, between Registrant and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.), rights agent, relating to the declaration of a rights dividend to Registrant s common shareholders of record on January 31, 1996 (incorporated by reference to Exhibit(a) to Registrant s Registration Statement on Form 8-A, dated January 24, 1996, SEC File No. 001-4300).
4.3	Amendment No. 1, dated as of January 31, 2006, to the Rights Agreement dated as of December 31, 1996, between Apache Corporation, a Delaware corporation, and Wells Fargo Bank, N.A. (as successor-in-interest to Norwest Bank Minnesota, N.A.) (incorporated by reference to Exhibit 4.4 to

	Registrant s Amendment No. 1 to Registration Statement on Form 8-A, dated January 31, 2006, SEC File No. 001-4300).
4.4	Senior Indenture, dated February 15, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank), formerly known as The Chase Manhattan Bank, as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).

Exhibit No.	Description
4.5	First Supplemental Indenture to the Senior Indenture, dated as of November 5, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.6	Form of Indenture among Apache Finance Pty Ltd, Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Registrant s Registration Statement on Form S-3, dated November 12, 1997, Reg. No. 333-339973).
4.7	Form of Indenture among Registrant, Apache Finance Canada Corporation and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to Registrant s Registration Statement on Form S-3, dated November 12, 1999, Reg. No. 333-90147).
10.1	Form of Amended and Restated Credit Agreement, dated as of May 9, 2006, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).
10.2	Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of April 5, 2007, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300).
10.3	Form of Request for Approval of Extension of Maturity Date and Amendment, dated as of February 18, 2008, among Registrant, the Lenders named therein, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A. and Bank of America, N.A., as Co-Syndication Agents, and BNP Paribas and UBS Loan Finance LLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300).
10.4	Form of Credit Agreement, dated as of May 12, 2005, among Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, J.P. Morgan Securities Inc. and Banc of America Securities, LLC, as Co-Lead Arrangers and Joint Bookrunners, Bank of America, N.A. and Citibank, N.A., as U.S. Co-Syndication Agents, and Calyon New York Branch and Société Générale, as U.S. Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.01 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
10.5	Form of Credit Agreement, dated as of May 12, 2005, among Apache Canada Ltd, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, RBC Capital Markets and BMO Nesbitt Burns, as Co-Lead Arrangers and Joint Bookrunners, Royal Bank of Canada, as Canadian Administrative Agent, Bank of Montreal and Union Bank of California, N.A., Canada Branch, as Canadian Co-Syndication Agents, and The

Toronto-Dominion Bank and BNP Paribas (Canada), as Canadian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.02 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).

Exhibit No.	Description
10.6	Form of Credit Agreement, dated as of May 12, 2005, among Apache Energy Limited, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as Co-Lead Arrangers and Joint Bookrunners, Citisecurities Limited, as Australian Administrative Agent, Deutsche Bank AG, Sydney Branch, and JPMorgan Chase Bank, as Australian Co-Syndication Agents, and Bank of America, N.A., Sydney Branch, and UBS AG, Australia Branch, as Australian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.03 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
10.7	Form of Request for Approval of Extension of Maturity Date and Amendment, dated April 5, 2007, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.6 to Registrant s Annual Report on Form 10-K for year ended December 31, 2007, SEC File No. 001-4300).
10.8	Form of Request for Approval of Extension of Maturity Date and Amendment, dated February 18, 2008, among Registrant, Apache Canada Ltd., Apache Energy Limited, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, and the other agents party thereto (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300).
10.9	Apache Corporation Corporate Incentive Compensation Plan A (Senior Officers Plan), dated July 16, 1998 (incorporated by reference to Exhibit 10.13 to Registrant s Annual Report on Form 10-K for year ended December 31, 1998, SEC File No. 001-4300). Apache Corporation Corporate Incentive Compensation Plan A (Senior Officers Plan), dated July 16, 1998 (incorporated by reference to Exhibit 10.13 to Registrant s Annual Report on Form 10-K for year ended December 31, 1998, SEC File No. 001-4300).
10.10	First Amendment to Apache Corporation Corporate Incentive Compensation Plan A, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.17 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.11	Apache Corporation Corporate Incentive Compensation Plan B (Strategic Objectives Format), dated July 16, 1998 (incorporated by reference to Exhibit 10.14 to Registrant s Annual Report on Form 10-K for year ended December 31, 1998, SEC File No. 001-4300).
10.12	First Amendment to Apache Corporation Corporate Incentive Compensation Plan B, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.19 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.13	Apache Corporation 401(k) Savings Plan, dated January 1, 2008 (incorporated by reference to Exhibit 10.20 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.14	Amendment to Apache Corporation 401(k) Savings Plan, dated January 29, 2009, effective as of January 1, 2009, except as otherwise specified (incorporated by reference to Exhibit 10.21 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
* 10.15	Amendment to Apache Corporation 401(k) Savings Plan, dated December 22, 2009, effective as of January 1, 2009, except as otherwise specified.

*	10.16	Non-Qualified Retirement/Savings Plan of Apache Corporation, amended and restated as of February 11, 2010.
*	10.17	Apache Corporation 2007 Omnibus Equity Compensation Plan, as amended and restated effective as of December 31, 2009.
	10.18	Apache Corporation 1998 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).

Exhibit No.	Description
10.19	Apache Corporation 2000 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).
10.20	Apache Corporation 2003 Stock Appreciation Rights Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.5 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2008, SEC File No. 001-4300).
10.21	Apache Corporation 2005 Stock Option Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.6 to Registrant s Quarterly Report on Form 10-Q for quarter ended September 30, 2008, Commission File No. 001-4300).
10.22	Apache Corporation 2005 Share Appreciation Plan, as amended and restated August 14, 2008 (incorporated by reference to Exhibit 10.7 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, Commission File No. 001-4300).
10.23	Apache Corporation 2008 Share Appreciation Program Specifications, pursuant to Apache Corporation 2007 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, SEC File No. 001-4300).
10.24	Apache Corporation Executive Restricted Stock Plan, as amended and restated November 19, 2008 (incorporated by reference to Exhibit 10.37 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.25	Apache Corporation Income Continuance Plan, as amended and restated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.35 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.26	Apache Corporation Deferred Delivery Plan, as amended and restated November 19, 2008, effective as of January 1, 2009, except as otherwise specified (incorporated by reference to Exhibit 10.36 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.27	Apache Corporation Non-Employee Directors Compensation Plan, as amended and restated November 20, 2008, effective as of January 1, 2009 (incorporated by reference to Exhibit 10.38 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).
10.28	Apache Corporation Outside Directors Retirement Plan, as amended and restated November 20, 2008, effective as of January 1, 2009 (incorporated by reference to Exhibit 10.39 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300)
10.29	Apache Corporation Equity Compensation Plan for Non-Employee Directors, as amended and restated February 8, 2007 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2007, SEC File No. 001-4300).
10.30	Apache Corporation Non-Employee Directors Restricted Stock Units Program Specifications, dated August 14, 2008, pursuant to Apache Corporation 2007 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.9 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, SEC File No. 001-4300).
10.31	Restated Employment and Consulting Agreement, dated January 15, 2009, between Registrant and Raymond Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K, dated January 15, 2009, filed January 16, 2009, SEC File No. 001-4300).
10.32	Amended and Restated Employment Agreement, dated December 20, 1990, between Registrant and John A. Kocur (incorporated by reference to Exhibit 10.10 to Registrant s Annual Report on

	Form 10-K for year ended December 31, 1990, SEC File No. 001-4300).
10.33	Employment Agreement between Registrant and G. Steven Farris, dated June 6, 1988, and First Amendment, dated November 20, 2008, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.44 to Registrant s Annual Report on Form 10-K for year ended December 31, 2008, SEC File No. 001-4300).

Exhibit No.	Description
10.34	Amended and Restated Conditional Stock Grant Agreement, dated September 15, 2005, effective January 1, 2005, between Registrant and G. Steven Farris (incorporated by reference to Exhibit 10.06 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.35	Restricted Stock Unit Award Agreement, dated May 8, 2008, between Registrant and G. Steven Farris (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for quarter ended March 31, 2008, SEC File No. 001-4300).
10.36	Form of Restricted Stock Unit Award Agreement, dated February 12, 2009, between Registrant and each of John A. Crum, Rodney J. Eichler, and Roger B. Plank (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K, dated February 12, 2009, filed February 18, 2009, SEC File No. 001-4300).
* 10.37	Form of Restricted Stock Unit Award Agreement, dated November 18, 2009, between Registrant and Michael S. Bahorich.
* 10.38	Form of Restricted Stock Unit Grant Agreement, dated May 6, 2009, between Registrant and each of G. Steven Farris, Roger B. Plank, John A. Crum, Rodney J. Eichler, and Michael S. Bahorich.
* 10.39	Form of Stock Option Award Agreement, dated May 6, 2009, between Registrant and each of G. Steven Farris, Roger B. Plank, John A. Crum, Rodney J. Eichler, and Michael S. Bahorich.
*12.1	Statement of Computation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends.
14.1	Code of Business Conduct (incorporated by reference to Exhibit 14.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2003, SEC File No. 001-4300).
*21.1	Subsidiaries of Registrant
*23.1	Consent of Ernst & Young LLP
*23.2	Consent of Ryder Scott Company L.P., Petroleum Consultants
*24.1	Power of Attorney (included as a part of the signature pages to this report).
*31.1	Certification of Principal Executive Officer
*31.2	Certification of Principal Financial Officer
*32.1	Certification of Principal Executive Officer and Principal Financial Officer
*99.1	Report of Ryder Scott Company L.P., Petroleum Consultants
**101	The following materials from the Apache Corporation s Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (Extensible Business Reporting Language): (i) Statement of Consolidated Operations, (ii) Statement of Consolidated Cash Flows, (iii) Consolidated Balance Sheet, (iv) Statement of Consolidated Shareholders Equity, and (v) Notes to Consolidated Financial Statements, tagged as blocks of text.

* Filed herewith.

** Furnished herewith.

Management contracts or compensatory plans or arrangements required to be filed herewith pursuant to Item 15 hereof.

NOTE: Debt instruments of the Registrant defining the rights of long-term debt holders in principal amounts not exceeding 10 percent of the Registrant s consolidated assets have been omitted and will be provided to the Commission upon request.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

APACHE CORPORATION

/s/ G. STEVEN FARRIS
G. Steven Farris
Chairman of the Board and Chief Executive Officer

Dated: February 26, 2010

POWER OF ATTORNEY

The officers and directors of Apache Corporation, whose signatures appear below, hereby constitute and appoint G. Steven Farris, Roger B. Plank, P. Anthony Lannie and Rebecca A. Hoyt, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this report and each of the undersigned does hereby ratify and confirm all that said attorneys shall do or cause to be done by virtue thereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ G. STEVEN FARRIS G. Steven Farris	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 26, 2010
/s/ ROGER B. PLANK Roger B. Plank	President (principal financial officer)	February 26, 2010
/s/ REBECCA A. HOYT Rebecca A. Hoyt	Vice President and Controller (principal accounting officer)	February 26, 2010
/s/ FREDERICK M. BOHEN Frederick M. Bohen	Director	February 26, 2010
/s/ RANDOLPH M. FERLIC Randolph M. Ferlic	Director	February 26, 2010
/s/ EUGENE C. FIEDOREK	Director	February 26, 2010

Eugene C. Fiedorek		
/s/ A. D. FRAZIER, JR.	Director	February 26, 2010
A. D. Frazier, Jr.		
/s/ PATRICIA ALBJERG GRAHAM	Director	February 26, 2010
Patricia Albjerg Graham		

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Name	Title	Date
/s/ JOHN A. KOCUR John A. Kocur	Director	February 26, 2010
/s/ GEORGE D. LAWRENCE George D. Lawrence	Director	February 26, 2010
/s/ F. H. MERELLI F. H. Merelli	Director	February 26, 2010
/s/ RODMAN D. PATTON Rodman D. Patton	Director	February 26, 2010
/s/ CHARLES J. PITMAN Charles J. Pitman	Director	February 26, 2010

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REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for the preparation and integrity of the consolidated financial statements appearing in this annual report on Form 10-K. The financial statements were prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management s best estimates and judgments.

Management of the Company is responsible for establishing and maintaining effective internal control over financial reporting as such term is defined in Rule 13a-15(f) under the Securities Exchange Act of 1934 (Exchange Act). The Company s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by a program on internal audits and appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by our Company s board of directors, applicable to all Company directors and all officers and employees of our Company and subsidiaries.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2009.

The Company s independent auditors, Ernst & Young LLP, a registered public accounting firm, are appointed by the Audit Committee of the Company s board of directors. Ernst & Young LLP have audited and reported on the consolidated financial statements of Apache Corporation and subsidiaries, and the effectiveness of the Company s internal control over financial reporting. The reports of the independent auditors follow this report on pages F-2 and F-3.

G. Steven Farris
Chairman of the Board and Chief Executive Officer
(principal executive officer)

Roger B. Plank
President
(principal financial officer)

Rebecca A. Hoyt
Vice President and Controller
(principal accounting officer)

Houston, Texas

February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Apache Corporation:

We have audited the accompanying consolidated balance sheets of Apache Corporation and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Apache Corporation and subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009, the Company adopted SEC Release 33-8995 and the amendments to ASC Topic 932, Extractive Industries Oil and Gas, resulting from ASU 2010-03 (collectively, the Modernization Rules).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Apache Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 26, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Apache Corporation:

We have audited Apache Corporation and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Apache Corporation and subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Apache Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Apache Corporation and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2009 of Apache Corporation and subsidiaries, and our report dated February 26, 2010, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 26, 2010

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APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per common share data)		
REVENUES AND OTHER:			
Oil and gas production revenues	$ 8,573,927	$ 12,327,839	$ 9,961,982
Other	40,899	61,911	37,770
	8,614,826	12,389,750	9,999,752
OPERATING EXPENSES:			
Depreciation, depletion and amortization			
Recurring	2,395,063	2,516,437	2,347,791
Additional	2,818,161	5,333,821	
Asset retirement obligation accretion	104,815	101,348	96,438
Lease operating expenses	1,662,140	1,909,625	1,652,855
Gathering and transportation	142,699	156,491	137,407
Taxes other than income	579,436	984,807	597,647
General and administrative	343,883	288,794	275,065
Financing costs, net	242,238	166,035	219,937
	8,288,435	11,457,358	5,327,140
INCOME (LOSS) BEFORE INCOME TAXES	326,391	932,392	4,672,612
Current income tax provision	841,899	1,456,382	970,728
Deferred income tax provision (benefit)	(231,110)	(1,235,944)	889,526
NET INCOME (LOSS)	(284,398)	711,954	2,812,358
Preferred stock dividends	7,294	5,680	5,680
INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ (291,692)	$ 706,274	$ 2,806,678
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ (0.87)	$ 2.11	$ 8.45
Diluted	$ (0.87)	$ 2.09	$ 8.39

The accompanying notes to consolidated financial statements are an integral part of this statement.

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APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (284,398)	$ 711,954	$ 2,812,358
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	5,213,224	7,850,258	2,347,791
Asset retirement obligation accretion	104,815	101,348	96,438
Provision for (benefit from) deferred income taxes	(231,110)	(1,235,944)	889,526
Other	182,611	(50,596)	48,967
Changes in operating assets and liabilities, net of effects of acquisitions:			
Receivables	(186,802)	570,592	(261,962)
Inventories	(5,172)	(22,295)	39,787
Drilling advances	(142,610)	28,846	(30,531)
Deferred charges and other	148,113	(323,832)	12,368
Accounts payable	(180,336)	(70,979)	(38,923)
Accrued expenses	(330,485)	(456,635)	(169,087)
Deferred credits and noncurrent liabilities	(64,207)	(37,373)	(69,299)
NET CASH PROVIDED BY OPERATING ACTIVITIES	4,223,643	7,065,344	5,677,433
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(3,325,710)	(5,143,603)	(4,301,044)
Additions to gathering, transmission and processing facilities	(305,389)	(679,405)	(480,936)
Acquisition of Anadarko properties			(1,004,593)
Acquisitions, other	(310,472)	(149,838)	(20,363)
Short-term investments	791,999	(791,999)	
Restricted cash	13,880	(13,880)	
Proceeds from sale of oil and gas properties	2,267	307,974	67,483
Other, net	(114,001)	(64,226)	(206,476)
NET CASH USED IN INVESTING ACTIVITIES	(3,247,426)	(6,534,977)	(5,945,929)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Commercial paper, credit facility and bank notes, net	248,169	(99,803)	(1,412,250)
Fixed-rate debt borrowings		796,315	1,992,290
Payments on fixed-rate notes	(100,000)	(353)	(173,000)
Dividends paid	(208,603)	(239,358)	(204,753)
Common stock activity	28,495	31,513	29,682
Redemption of preferred stock	(98,387)		
Treasury stock activity, net	5,620	4,498	14,279

Cost of debt and equity transactions	(655)	(7,050)	(18,179)
Other	15,811	39,498	25,726
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(109,550)	525,260	253,795
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	866,667	1,055,627	(14,701)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,181,450	125,823	140,524
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 2,048,117	$ 1,181,450	$ 125,823
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 243,041	$ 171,487	$ 181,138
Income taxes paid, net of refunds	686,411	1,694,557	797,589

The accompanying notes to consolidated financial statements are an integral part of this statement.

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APACHE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,048,117	$ 1,181,450
Short-term investments		791,999
Receivables, net of allowance	1,545,699	1,356,979
Inventories	533,251	498,567
Drilling advances	230,733	93,377
Prepaid taxes	146,653	303,203
Prepaid assets and other	81,396	225,399
	4,585,849	4,450,974
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	44,267,037	40,639,281
Unproved properties and properties under development, not being amortized	1,479,008	1,300,347
Gathering, transmission and processing facilities	3,189,177	2,883,789
Other	492,511	452,989
	49,427,733	45,276,406
Less: Accumulated depreciation, depletion and amortization	(26,527,118)	(21,317,889)
	22,900,615	23,958,517
OTHER ASSETS:		
Restricted cash		13,880
Goodwill, net	189,252	189,252
Deferred charges and other	510,027	573,862
	$ 28,185,743	$ 29,186,485
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 396,564	$ 548,945
Accrued operating expense	90,151	168,531
Accrued exploration and development	923,084	964,859
Accrued compensation and benefits	151,408	111,907
Current debt	117,326	112,598
Asset retirement obligations	146,654	339,155

Derivative instruments	128,219	
Other	439,152	274,440
	2,392,558	2,520,435
LONG-TERM DEBT	4,950,390	4,808,975
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	2,764,901	3,166,657
Asset retirement obligation	1,637,357	1,555,529
Other	661,916	626,168
	5,064,174	5,348,354
COMMITMENTS AND CONTINGENCIES (Note 8)		
SHAREHOLDERS EQUITY:		
Preferred stock, no par value, 5,000,000 shares authorized Series B, 5.68% Cumulative, $100 million aggregate liquidation value, 100,000 shares redeemed in 2009, 100,000 issued and outstanding in 2008		98,387
Common stock, $0.625 par, 430,000,000 shares authorized, 344,076,790 and 342,754,114 shares issued, respectively	215,048	214,221
Paid-in capital	4,634,326	4,472,826
Retained earnings	11,436,580	11,929,827
Treasury stock, at cost, 7,639,818 and 8,044,050 shares, respectively	(216,831)	(228,304)
Accumulated other comprehensive income (loss)	(290,502)	21,764
	15,778,621	16,508,721
	$ 28,185,743	$ 29,186,485

The accompanying notes to consolidated financial statements are an integral part of this statement.

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APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED SHAREHOLDERS EQUITY

	Comprehensive Income (Loss)	Series B Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Tot Shareh Equ
				(In thousands)				
VCE AT IBER 31, 2006		$ 98,387	$ 212,365	$ 4,269,795	$ 8,898,577	$ (256,739)	$ (31,332)	$ 13,19
hensive income:								
ome	$ 2,812,358				2,812,358			2,8
rement, net of tax of $4,896	6,333						6,333	
dity hedges, net ne tax of $272,865	(495,212)						(495,212)	(49
hensive income	$ 2,323,479							
vidends:								
d					(5,680)			
n ($.60 per					(199,401)			(19
n shares issued			961	48,144				4
shares issued,				1,834		18,475		2
sation expense				48,816				4
erves					(48,502)			(4
				(1,440)	240			
VCE AT IBER 31, 2007		98,387	213,326	4,367,149	11,457,592	(238,264)	(520,211)	15,37
hensive income:								
ome	$ 711,954				711,954			7
rement, net of tax of $7,495	(7,530)						(7,530)	
dity hedges, net ne tax of $301,157	549,505						549,505	54
hensive income	$ 1,253,929							

vidends:								
d					(5,680)			
n ($.70 per								
					(233,952)			(2
n shares issued			895	36,722				3
y shares issued,								
				(442)		9,960		
sation expense				93,762				9
erves				(23,663)				(2
				(702)	(87)			
NCE AT								
MBER 31, 2008		98,387	214,221	4,472,826	11,929,827	(228,304)	21,764	16,50
hensive loss:								
	$ (284,398)				(284,398)			(28
rement, net of								
tax								
of $4,754	(4,533)						(4,533)	
dity hedges, net								
ne tax								
of $171,310	(307,733)						(307,733)	(30
hensive loss	$ (596,664)							
vidends:								
d					(7,294)			
n ($.60 per								
					(201,555)			(20
d stock								
ion		(98,387)						(9
n shares issued			827	14,916				
y shares issued,								
				(5,262)		11,473		
sation expense				128,523				12
erves				23,695				2
				(372)				
NCE AT								
MBER 31, 2009		$	$ 215,048	$ 4,634,326	$ 11,436,580	$ (216,831)	$ (290,502)	$ 15,77

The accompanying notes to consolidated financial statements are an integral part of this statement.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

General Accounting Description

Nature of Operations

Apache Corporation (Apache or the Company) is an independent energy company that explores for, develops and produces natural gas, crude oil and natural gas liquids. The Company s North American exploration and production activities are divided into two United States (U.S.) operating regions (Central and Gulf Coast) and a Canadian region. Approximately 62 percent (unaudited) of the Company s proved reserves are located in North America. Outside of North America, Apache has exploration and production interests in Egypt, offshore Western Australia, offshore the United Kingdom in the North Sea (North Sea) and Argentina. Apache also has exploration interests on the Chilean side of the island of Tierra del Fuego.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by Apache and its subsidiaries reflect industry practices and conform to accounting principles generally accepted in the U.S. (GAAP). Certain reclassifications have been made to prior periods to conform to the current-year presentation. Significant policies are discussed below.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Apache and its subsidiaries after elimination of intercompany balances and transactions. The Company consolidates all investments in which the Company, either through direct or indirect ownership, has more than a 50-percent voting interest. In addition, Apache consolidates all variable interest entities where it is the primary beneficiary. The Company s interest in oil and gas exploration and production ventures and partnerships are proportionately consolidated.

Use of Estimates

Preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Apache evaluates its estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of its financial statements and changes in these estimates are recorded when known. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (see Note 13 Supplemental Oil and Gas Disclosures), asset retirement obligations and income taxes.

Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less at time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. As of

December 31, 2009 and 2008, Apache had $2.0 billion and $1.2 billion, respectively, of cash and cash equivalents.

Marketable Securities

The Company accounts for investments in debt and equity securities in accordance with the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC, also known collectively as the Codification) Topic 320, Investments Debt and Equity Securities. Investments in debt securities classified as held to maturity are recorded at cost. As of December 31, 2009, Apache held no marketable securities. At December 31, 2008, the Company had $792 million invested in obligations of the U.S. government with original maturities greater than three months but less than a year.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Allowance for Doubtful Accounts

The Company routinely assesses the collectibility of all material trade and other receivables. Many of Apache s receivables are from joint interest owners on properties Apache operates. Thus, Apache may have the ability to withhold future revenue disbursements to recover any non-payment of these joint interest billings. Generally, the Company s crude oil and natural gas receivables are collected within two months. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. As of December 31, 2009 and 2008, the Company had an allowance for doubtful accounts of $38 million and $33 million, respectively.

While Apache experienced a decline in the timeliness of receipts from the Egyptian General Petroleum Corporation (EGPC) for oil and gas sales in recent years, the Company saw significant improvement in collections throughout 2009.

Inventories

Inventories consist principally of tubular goods and equipment, stated at the weighted-average cost, and oil produced but not sold, stated at the lower of cost or market.

Oil and Gas Property

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, including salaries and benefits, but does not include any costs related to production, general corporate overhead or similar activities. Historically, total capitalized internal costs in any given year have not been material to total oil and gas costs capitalized in such year. Apache capitalized $219 million, $236 million and $208 million of these internal costs in 2009, 2008 and 2007, respectively. Proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion (greater than 25 percent) of the Company s reserve quantities in a particular country are sold, in which case a gain or loss is recognized in income.

In December 2007 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised), Business Combinations (SFAS No. 141(R)), which was amended by FASB Staff Position (FSP) FAS No. 141(R)-1 in April 2009. This guidance has been primarily codified into the FASB Accounting Standards Codification (ASC, also known collectively as the Codification) Topic 805, Business Combinations. The guidance broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, the standard establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interests in the acquiree and the goodwill acquired. The statement requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction. It also modifies disclosure requirements. Apache adopted this statement effective January 1, 2009. However, since the Company did not close any material business combinations during the 2009, the adoption had a negligible impact on the Company s consolidated financial statements.

Costs Excluded

Oil and gas unevaluated properties and properties under development include costs that are excluded from costs being depreciated or amortized. These costs represent investments in unproved properties and major development projects in which the Company owns a direct interest. Apache excludes these costs on a country-by-country basis until proved reserves are found, until it is determined that the costs are impaired, or until major development projects are placed in service. All costs excluded are reviewed at least quarterly to determine if

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APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

impairment has occurred. In countries where proved reserves exist, exploratory drilling costs associated with dry holes are transferred to proved properties immediately upon determination that a well is dry and amortized accordingly. Also, geological and geophysical (G&G) costs not associated with specific properties are recorded to proved property. For international operations where a reserve base has not yet been established, impairments are charged to earnings and are determined through an evaluation considering, among other factors, seismic data, requirements to relinquish acreage, drilling results, remaining time in the commitment period, remaining capital plan and political, economic and market conditions.

Ceiling Test

Under the existing full-cost method of accounting, a ceiling test is performed each quarter. The test establishes a limit (ceiling), on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization (DD&A) and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is the estimated after-tax future net cash flows from proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet. In January 2009, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting (Release 33-8995), amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which amends ASC Topic 932, Extractive Industries Oil and Gas (ASC Topic 932) to align the guidance with the changes made by the SEC. The Company adopted Release 33-8995 and the amendments to ASC Topic 932 resulting from ASU 2010-03 (collectively, the Modernization Rules) effective December 31, 2009.

The estimate of after-tax future net cash flows as of December 31, 2009 is 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 2009, held flat for the life of the production, except where prices are defined by contractual arrangements. Prior to adoption of the Modernization Rules, effective in the fourth quarter of 2009, estimated after-tax future net cash flows were calculated using commodity prices in effect at the end of each quarter. If capitalized costs exceed this ceiling, the excess is charged to expense and reflected as additional DD&A. Excluding the effect of cash flow hedges in calculating the ceiling limitation at December 31, 2009, capitalized costs still would not have exceeded the ceiling limitation. See Note 13 Supplemental Oil and Gas Disclosures for a discussion on calculation of estimated future net cash flows.

Under the existing full-cost accounting rules, the Company recorded 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 on December 31, 2008, as a result of the ceiling test limitations. Under those same rules, which were in effect for the first three quarterly reporting periods in 2009, the Company recorded an additional $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 on March 31, 2009. These write-downs are reflected as additional DD&A expense in the accompanying Statement of Consolidated Operations. Excluding the effects of cash flow hedges in calculating the ceiling limitation, the write-downs as of December 31, 2008, and March 31, 2009 would have been $5.9 billion ($4.0 billion net of tax) and $3.4 billion ($2.4 billion net of tax), respectively.

Gathering, Transmission and Processing Facilities

The Company assesses the carrying amount of its gathering, transmission and processing facilities annually and whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. If the carrying amount of these facilities is less than the sum of the undiscounted cash flows expected to result from their use and eventual disposition, an impairment loss is recorded through a charge to expense. Gathering, transmission

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and processing facilities totaled $3.2 billion and $2.9 billion at December 31, 2009 and 2008, respectively. No impairment of gathering, transmission and processing facilities was recognized during 2009, 2008 or 2007.

Depreciation, Depletion and Amortization

DD&A of oil and gas properties is calculated quarterly, on a country-by-country basis, using the Units of Production Method (UOP). The UOP calculation, in simplest terms, multiplies the percentage of estimated proved reserves produced each quarter times the costs of those reserves. The result is to recognize expense at the same pace that the reservoirs are actually depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated DD&A, estimated future development costs (future costs to access and develop reserves) and asset retirement costs which are not already included in oil and gas property, less related salvage value.

Gas gathering, transmission and processing facilities, buildings and equipment are depreciated on a straight-line basis over the estimated useful lives of the assets, which range from three to 20 years. Accumulated depreciation for these assets totaled $1 billion and $870 million at December 31, 2009 and 2008, respectively.

Asset Retirement Obligation

The initial estimated asset retirement obligation (ARO) related to properties is recognized as a liability, with an associated increase in property and equipment for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated ARO changes, an adjustment is recorded to both the ARO and the asset retirement cost. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling ARO.

Capitalized Interest

Interest is capitalized on oil and gas investments in unproved properties and exploration and development activities that are in progress. Major construction projects also qualify for interest capitalization up until the time the assets are ready for service. Capitalized interest is calculated by multiplying the Company s weighted-average interest rate on debt by the amount of qualifying costs. For projects under construction that carry their own financing, interest is calculated using the interest rate related to the project financing. Interest and related costs are capitalized until each project is complete. Capitalized interest cannot exceed gross interest expense. Capitalized interest associated with unproved properties is transferred to proved properties along with the associated unproved property balance. As major construction projects are completed, the associated capitalized interest is amortized over the useful life of the related asset. Capitalized interest totaled $61 million, $94 million and $76 million in 2009, 2008 and 2007, respectively.

Goodwill

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. The Company assesses the carrying amount of goodwill by testing the goodwill for impairment annually and when impairment indicators arise. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then goodwill is written down to the implied fair value of the goodwill through a charge to expense. Goodwill totaled

$189 million at December 31, 2009 and 2008, with approximately $103 million and $86 million recorded in Canada and Egypt, respectively. Each country was assessed as a reporting unit. No impairment of goodwill was recognized during 2009, 2008 or 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts Payable

Included in accounts payable at December 31, 2009 and 2008, are liabilities of approximately $98 million and $164 million, respectively, representing the amount by which checks issued, but not presented to the Company s banks for collection, exceeded balances in applicable bank accounts.

Commitments and Contingencies

Accruals for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change.

Revenue Recognition and Imbalances

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

Apache uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Apache is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties estimated remaining reserves net to Apache will not be sufficient to enable the under-produced owner to recoup its entitled share through production. The Company s recorded liability is generally reflected in other non-current liabilities. No receivables are recorded for those wells where Apache has taken less than its share of production. Gas imbalances are reflected as adjustments to estimates of proved gas reserves and future cash flows in the unaudited supplemental oil and gas disclosures.

Apache markets its own U.S. natural gas production. As the Company s production fluctuates because of operational issues, it is occasionally necessary to purchase gas (third-party gas) to fulfill its sales obligations and commitments. Both the costs and sales proceeds of this third-party gas are reported on a net basis in oil and gas production revenues. The costs of third-party gas netted against the related sales proceeds totaled $34 million, $56 million and $123 million, for 2009, 2008 and 2007, respectively.

The Company s Egyptian operations are conducted pursuant to production sharing contracts under which contractor partners pay all operating and capital costs for exploring and developing the concessions. A percentage of the production, generally up to 40 percent, is available to contractor partners to recover these operating and capital costs over contractually defined terms. The balance of the production is split among the contractor partners and the EGPC on a contractually defined basis. Cost recovery is reflected in revenue.

Derivative Instruments and Hedging Activities

Apache periodically enters into derivative contracts to manage its exposure to commodity price risk. These derivative contracts, which are generally placed with major financial institutions that the Company believes are minimal credit risks, may take the form of forward contracts, futures contracts, swaps or options. The oil and gas reference prices, upon which the commodity derivative contracts are based, reflect various market indices that have a high degree of historical correlation with actual prices received by the Company for its oil and gas production.

Apache accounts for its derivative instruments in accordance with ASC Topic 815, Derivatives and Hedging, which requires that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the balance sheet as either an asset or liability measured at fair value (which is generally based on information obtained from an independent investment banking firm). Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on cash flow hedges to be deferred in other comprehensive income. Realized gains and losses from the Company s oil and gas cash flow hedges, including terminated contracts, are generally recognized in oil and gas

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

production revenues when the forecasted transaction occurs. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current-period income as Other under Revenues and Other in the Statement of Consolidated Operations. If at any time the likelihood of occurrence of a hedged forecasted transaction ceases to be probable, hedge accounting treatment will cease on a prospective basis, and all future changes in the fair value of the derivative will be recognized directly in earnings. Amounts recorded in other comprehensive income prior to the change in the likelihood of occurrence of the forecasted transaction will remain in other comprehensive income until such time as the forecasted transaction impacts earnings. If it becomes probable that the original forecasted production will not occur, then the derivative gain or loss would be reclassified from accumulated other comprehensive income into earnings immediately. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, and any ineffectiveness is immediately reported as Other under Revenues and Other in the Statement of Consolidated Operations.

General and Administrative Expense

General and administrative expenses are reported net of recoveries from owners in properties operated by Apache and net of amounts related to lease operating activities or capitalized pursuant to the full-cost method of accounting.

Income Taxes

Apache records deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

Earnings from Apache s international operations are permanently reinvested; therefore, the Company does not recognize U.S. deferred taxes on the unremitted earnings of its international subsidiaries. If it becomes apparent that some or all of the unremitted earnings will be remitted, the Company will then recognize taxes on those earnings.

Foreign Currency Translation

The U.S. dollar has been determined to be the functional currency for each of Apache s international operations. The functional currency is determined country-by-country based on relevant facts and circumstances of the cash flows, commodity pricing environment and financing arrangements in each country. Foreign currency translation gains and losses arise when monetary assets and liabilities denominated in foreign currencies are remeasured to their U.S. dollar equivalent at the exchange rate in effect at the end of each reporting period.

The Company accounts for foreign currency gains and losses in accordance with ASC Topic 830, Foreign Currency Matters. Foreign currency translation gains and losses related to current taxes payable and deferred tax liabilities are recorded as a component of provision for income taxes. In 2009, the Company recorded additional net tax expense of $195 million, including a current tax benefit of $3 million and deferred tax expense of $198 million, in connection with foreign currency translation gains and losses. In 2008, Apache recorded an additional tax benefit of $400 million, including a current benefit of $3 million and a deferred benefit of $397 million. In 2007, the Company recorded additional deferred tax expense of $228 million. Foreign currency translation gains and losses had a negligible impact on current tax expense in 2007. For further discussion, see Note 6 Income Taxes. All other foreign currency translation gains and losses are reflected in Other under Revenues and Other in the Statement of Consolidated Operations. The Company s other foreign currency gains and losses included in Other under Revenues and Other in the Statement of Consolidated Operations netted to gains of $11 million, $38 million and $9 million in 2009, 2008 and 2007, respectively.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign currency gains and losses also arise when revenue and disbursement transactions denominated in a country s local currency are converted to a U.S. dollar equivalent based on the average exchange rates during the reporting period.

Insurance Coverage

The Company recognizes an insurance receivable when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment.

Earnings Per Share

The Company s basic earnings per share (EPS) amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS reflects the potential dilution, using the treasury-stock method, which assumes that options were exercised and restricted stock was fully vested.

Diluted EPS also includes the impact of unvested share appreciation plans. For awards in which the share price goals have already been achieved, shares are included in diluted EPS using the treasury-stock method. For those awards in which the share price goals have not been achieved, the number of contingently issuable shares included in the diluted EPS is based on the number of shares, if any, using the treasury-stock method, that would be issuable if the market price of the Company s stock at the end of the reporting period exceeded the share price goals under the terms of the plan.

Unvested share-based payment awards that contain rights to receive nonforfeitable dividends or dividend equivalents are participating securities prior to vesting and, therefore, are included in the earnings allocations in computing basic EPS under the two-class method.

Stock-Based Compensation

The Company accounts for stock-based compensation under the fair value recognition provisions of ASC Topic 718, Compensation Stock Compensation. The Company grants various types of stock-based awards including stock options, nonvested restricted stock units and performance-based awards. In 2003 and 2004, the Company also granted cash-based stock appreciation rights. These plans and related accounting policies are defined and described more fully in Note 7 Capital Stock. Stock compensation awards granted are valued on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

ASC Topic 718 also requires that benefits of tax deductions in excess of recognized compensation cost be reported as financing cash flows rather than as operating cash flows. The Company classified $16 million, $47 million and $30 million as financing cash inflows in 2009, 2008 and 2007, respectively.

Treasury Stock

The Company follows the weighted-average-cost method of accounting for treasury stock transactions.

Recently Issued Accounting Standards Not Yet Adopted

All new accounting pronouncements previously issued have been adopted as of or prior to December 31, 2009.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. SIGNIFICANT ACQUISITIONS AND DIVESTITURES

2009 Activity

During the second quarter of 2009 Apache announced the acquisition of nine Permian Basin oil and gas fields with then current net production of 3,500 barrels of oil equivalent per day from Marathon Oil Corporation for $187.4 million, subject to normal post-closing adjustments. Estimated reserves acquired in connection with the acquisition totaled 19.5 MMboe (unaudited). These long-lived fields fit well with Apache s existing properties in the Permian Basin, particularly in Lea County, N.M., and will provide the Company many years of drilling opportunities. The effective date of the transaction was January 1, 2009.

2008 Activity

There was no major acquisition activity during 2008; however, the Company completed several divestiture transactions. On January 29, 2008, the Company completed the sale of its interest in Ship Shoal blocks 349 and 359 on the outer continental shelf of the Gulf of Mexico to W&T Offshore, Inc. for $116 million. On January 31, 2008, the Company completed the sale of non-strategic oil and gas properties in the Permian Basin of West Texas to Vanguard Permian, LLC for $78 million. On April 2, 2008, the Company completed the sale of non-strategic Canadian properties to Central Global Resources for C$112 million. These divestitures were subject to normal post-closing adjustments.

2007 Activity

U.S. Gulf Coast Farm-in On September 6, 2007, Apache entered into an Exploration Agreement with various EnerVest Partnerships (EVP) for an initial term of four years whereby Apache committed to spend $30 million in qualified expenditures to explore, drill, produce and market hydrocarbons from specified undeveloped formations across 400,000 net acres in Central and East Texas. As of December 31, 2008, Apache had fulfilled the $30 million commitment.

U.S. Permian Basin On March 29, 2007, the Company closed its acquisition of controlling interest in 28 oil and gas fields in the Permian Basin of West Texas from Anadarko for $1 billion. Apache estimates that these fields had proved reserves of 57 million barrels (MMbbls) (unaudited) of liquid hydrocarbons and 78 billion cubic feet (Bcf) (unaudited) of natural gas as of year-end 2006. The Company funded the acquisition with debt. Apache and Anadarko entered into a joint-venture arrangement to effect the transaction. The Company entered into cash flow hedges for a portion of the crude oil and natural gas production.

3. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Objectives and Strategies

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its worldwide production. Apache s first strategy is to maintain a balance in its commodities mix of oil and gas, and gas sold at New York Mercantile Exchange (NYMEX)-related prices versus gas sold under long-term contracts tied to oil prices.

Management also believes it is prudent to manage the variability in cash flows on a portion of its crude oil and natural gas production. The Company utilizes various types of derivative financial instruments, including swaps and options, to manage fluctuations in cash flows resulting from changes in commodity prices. Derivative instruments entered into are designated as cash flow hedges.

Counterparty Risk

The use of derivative instruments exposes the Company to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. Apache s commodity derivative instruments are with a diversified group of counterparties, primarily financial institutions. To reduce the concentration of exposure to any

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

individual counterparty, Apache had positions with 16 counterparties as of December 31, 2009. All of these counterparties were at year-end rated A or higher by Standard & Poor s and A2 or higher by Moody s. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, Apache may not realize the benefit of some of its derivative instruments under lower commodity prices.

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs a material deterioration in its credit ratings, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a transfer or terminate the arrangement.

Commodity Derivative Instruments

As of December 31, 2009, Apache had the following open crude oil derivative positions:

	Fixed-Price Swaps		Collars		
Production Period	**Mbbls**	**Weighted Average Fixed Price(1)**	**Mbbls**	**Weighted Average Floor Price(1)**	**Weighted Average Ceiling Price(1)**
2010	2,383	$ 68.71	10,396	$ 65.01	$ 80.84
2011	3,650	70.12	6,202	66.24	87.04
2012	3,292	70.99	2,554	66.07	89.13
2013	1,451	72.01			
2014	76	74.50			

(1) Crude oil prices represent a weighted average of several contracts entered into on a per barrel basis. Crude oil contracts are primarily settled against NYMEX WTI Cushing Index.

As of December 31, 2009, Apache had the following open natural gas derivative positions:

	Fixed-Price Swaps			Collars			
Production Period	**MMBtu (in 000 s)**	**GJ (in 000 s)**	**Weighted Average Fixed Price(1)**	**MMBtu (in 000 s)**	**GJ (in 000 s)**	**Weighted Average Floor Price(1)**	**Weighted Average Ceiling Price(1)**
2010	82,125		$ 5.81	30,550		$ 5.48	$ 7.07

2010		54,750	5.37				
2011	10,038		6.61	9,125		5.00	8.85
2011		23,725	6.75		3,650	6.50	7.10
2012	2,745		6.73	10,980		5.75	8.43
2012		29,280	6.95		7,320	6.50	7.27
2013	1,825		7.05				
2014	755		7.23				

(1) U.S. natural gas prices represent a weighted average of several contracts entered into on a per million British thermal units (MMBtu) basis and are settled primarily against NYMEX Henry Hub and various Inside FERC indices. The Canadian natural gas prices represent a weighted average of AECO Index prices. The Canadian gas contracts are entered into on a per gigajoule (GJ) basis and are settled against AECO Index. These Canadian gas contracts are shown in Canadian dollars.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2009, Apache had the following open natural gas financial basis swap contracts:

Production Period	MMBtu (in 000 s)		Weighted Average Price Differential(1)
2010	41,975	$	(0.54)

(1) Natural gas financial basis swap contracts represent a weighted average differential between prices primarily at Inside FERC PEPL and NYMEX Henry Hub prices.

Fair Values of Derivative Instruments Recorded in the Consolidated Balance Sheet

The Company accounts for derivative instruments and hedging activity in accordance with ASC Topic 815, Derivatives and Hedging, and all derivative instruments are reflected as either assets or liabilities at fair value in the Consolidated Balance Sheet. These fair values are recorded by netting asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. The fair market value of the Company s derivative assets and liabilities are as follows:

		December 31, 2009		December 31, 2008
		(In millions)		
Current Assets: Prepaid assets and other	$	13	$	154
Other Assets: Deferred charges and other		51		65
Total Assets	$	64	$	219
Current Liabilities: Derivative instruments	$	128	$	
Noncurrent Liabilities: Other		202		7
Total Liabilities	$	330	$	7

The methods and assumptions used to estimate the fair values of the Company s commodity derivative instruments and gross amounts of commodity derivative assets and liabilities are more fully discussed in Note 10 Fair Value Measurements.

Commodity Derivative Activity Recorded in Statement of Consolidated Operations

The following table summarizes the effect of derivative instruments on the Company s Statement of Consolidated Operations:

	Gain (Loss) on Derivatives Recognized in Operations	For the Year Ended December 31, 2009	2008 (In millions)	2007
Gain (loss) reclassified from accumulated other comprehensive income (loss) into operations (effective portion)	Oil and Gas Production Revenues	$ 176	$ (431)	$ (31)
Gain (loss) on derivatives recognized in operations (ineffective portion and basis)	Revenues and Other: Other	$ 2	$ (1)	$

Commodity Derivative Activity in Accumulated Other Comprehensive Income (Loss)

As of December 31, 2009, the Company s derivative instruments were designated as cash flow hedges in accordance with ASC Topic 815. A reconciliation of the components of accumulated other comprehensive income

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(loss) in the Statement of Consolidated Shareholders Equity related to Apache s cash flow hedges is presented in the table below:

	2009		2008		2007	
	Before tax	After tax	Before tax	After tax	Before tax	After tax
	(In millions)					
Unrealized gain (loss) on derivatives at beginning of year	$ 212	$ 138	$ (639)	$ (412)	$ 129	$ 84
Realized amounts reclassified into earnings	(176)	(120)	431	279	31	18
Net change in derivative fair value	(302)	(187)				