APACHE CORP
Form 10-K
February 29, 2008

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, 2007,

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

A Delaware Corporation	**IRS Employer No. 41-0747868**

One Post Oak Central
2000 Post Oak Boulevard, Suite 100
Houston, Texas 77056-4400
Telephone Number (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 NASDAQ National Market
Preferred Stock Purchase Rights	New York Stock Exchange 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 of 1933. 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 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, 2007	$ 27,088,457,168
Number of shares of registrant s common stock outstanding as of January 31, 2008	332,991,134

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of registrant s proxy statement relating to registrant s 2008 annual meeting of stockholders have been incorporated by reference into Part III hereof.

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DESCRIPTION

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. Quantities of natural gas are expressed in this report in terms of thousand cubic feet (Mcf), million cubic feet (MMcf), billion cubic feet (Bcf) or trillion cubic feet (Tcf). Oil is quantified in terms of barrels (bbls); thousands of barrels (Mbbls) and millions of barrels (MMbbls). Natural gas is compared to oil in terms of barrels of oil equivalent (boe) or million barrels of oil equivalent (MMboe). Oil and natural gas liquids are compared with natural gas in terms of million cubic feet equivalent (MMcfe) and billion cubic feet equivalent (Bcfe). One barrel of oil is the energy equivalent of six Mcf of natural gas. Daily oil and gas production is expressed in terms of barrels of oil per day (b/d) and thousands or millions of cubic feet of gas per day (Mcf/d and MMcf/d, respectively) or millions of British thermal units per day (MMBtu/d). Gas sales volumes may be expressed in terms of one million British thermal units (MMBtu), which is approximately equal to one Mcf. With respect to information relating to our working interest *in wells or acreage, net oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.*

PART I

ITEMS 1 AND 2. *BUSINESS AND PROPERTIES*

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 United Kingdom (U.K.) in the North Sea (North Sea), and onshore Argentina. In November 2007, we were high bidder on two exploration blocks 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 24, 2007, we filed certifications of our compliance with the listing standards of the NYSE and the NASDAQ, including our chief executive officer s certification of compliance with the NYSE standards. Through our website, http://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 Securities and Exchange Commission (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 chief executive officer and our chief 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 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.

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 referred to in this document may be held by those subsidiaries. We treat all operations as one line of business.

Growth Strategy

Apache s mission is to grow a profitable upstream oil and gas company for the long-term benefit of our shareholders. Our strategy is to build a portfolio of core areas which provide long-term growth opportunities through grass-roots drilling supplemented by occasional acquisitions. Two decades ago, recognizing that the United States was a mature oil and gas province, we launched an international exploration component to our portfolio approach, which provides exposure to larger reserve targets with which to continue production and reserve growth. We have producing operations in six countries, comprised of seven regions the United States (Gulf Coast and Central regions), Canada, Egypt, the North Sea, Australia and Argentina. We are finalizing contracts for two exploration blocks in Chile. We seek to grow profitably while building critical mass that supports sustainable, lower-risk, repeatable drilling opportunities. This enables us to pursue higher-risk, higher-reward exploration primarily in our international regions; particularly our growth areas of Australia, Canada and Egypt. We also seek a balance in terms of product mix and geologic and geographic risk, in order to achieve consistency in our results. As a testament to our balanced portfolio approach Apache increased production for the 28^{th} out of 29 years and reserves for the 22^{nd} consecutive year.

Operating regions are given the autonomy necessary to make drilling and operating decisions and to act quickly. Management and incentive systems motivate appropriate risk taking to reach or exceed targeted hurdle rates of return. These are measured monthly, reviewed quarterly with senior management and utilized in determining annual performance rewards. Apache is also one of the leading acquirers of three-dimensional (3-D) seismic data in the industry today. Our geophysical personnel have developed strategies for rapid and cost-effective acquisition and processing of 3-D data, enabling our technical teams to analyze large swaths of acreage, generate drilling prospects on an accelerated timetable and lessen drilling risk.

In 2008, we are planning another active year of drilling and have set a preliminary exploration and development budget of approximately $4.6 billion, or nine percent more than 2007. Our 2008 plan also includes just under $400 million for gathering, transmission and processing (GTP) assets. As is our custom, we will review and revise our capital expenditure estimates throughout the year based on changing industry conditions and results-to-date. Additionally, we continually look for opportunities to acquire producing oil and gas properties where we believe we can add value and earn adequate rates of return and may take advantage of such acquisition opportunities should they arise.

North America

In the U.S., the Gulf Coast region consistently delivers high returns on invested capital and cash flow significantly in excess of its exploration and development spending. Occasional acquisitions have played an important role because with steep decline rates, 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 in the areas of the Permian basin of West Texas and New Mexico, East Texas and the Anadarko basin of western Oklahoma. Apache s future growth in the U.S. is more likely to be achieved through a combination of drilling and acquisitions, rather than through drilling activity alone. Our March 2007 $1 billion acquisition of properties in the Permian basin, for example, complimented our active drilling program in 2007, buttressed our growth in the U.S. and brought numerous opportunities to increase future production through workovers, recompletions and drilling.

In Canada, we have five million net acres across the provinces of British Columbia, Alberta and Saskatchewan. We have a significant inventory of low-risk drilling opportunities in and around a number of Apache fields in Alberta, including Provost, Hatton, Nevis, Kaybob and West 5. With significant increases in Canadian acquisition and land costs, our 2004 and 2005 agreements with Exxon Mobil Corporation (ExxonMobil) provide a way for Apache to earn acreage through drilling with no upfront costs, while ExxonMobil retains a royalty on fee lands and a convertible working interest on leasehold acreage. We also have emerging resource plays in the gas bearing shales of Northeast British Columbia (NEBC), where we have now acquired 200,000 highly prospective net acres, and in the Manville coals of central Alberta. A recent ill-conceived change in Alberta royalty rates will limit our investment there, primarily to shallow drilling activity and divert investments to Saskatchewan or British Columbia.

International

In Egypt s Western Desert, Apache s 18.9 million gross acres encompass a sizable resource in the Cretaceous Upper Bahariya formations and outstanding exploration potential in deeper intervals from lower Cretaceous to Jurassic. The Qasr gas and condensate field, discovered in 2003, is the largest ever found by Apache with ultimate recoverable reserves of an estimated 2.25 Tcf of gas and 80 MMbbls of associated liquids. Apache s gas production is restricted because Western Desert infrastructure is at capacity. Two new gas trains will add 100 MMcf/d of capacity each and are currently under construction with completion slated for around year-end 2008. Our historical growth in Egypt has been driven by drilling and Apache is the most active driller in Egypt.

In Australia, Apache s recent expansion beyond our core holdings in the Carnarvon basin is beginning to pay off. In the Exmouth basin, development of prior-year discoveries at the Van Gogh and Pyrenees fields, sanctioned in 2007, is progressing. The Van Gogh development is operated by Apache and the Pyrenees development is operated by BHP Billiton. Production from each field is estimated at 20,000 b/d net to Apache. Van Gogh development drilling has commenced with first oil production expected in the first half of 2009. Pyrenees development drilling is expected to commence in 2009 with first oil production expected in 2010. In the Gippsland basin, we acquired nearly 1.5 million net acres over the past several years and have generated an inventory of high-risk, high-potential exploration prospects with drilling to commence in 2008. Development drilling at the Reindeer discovery and the construction of pipeline and processing infrastructure is scheduled to commence in 2008 with first production anticipated in 2010. The Julimar gas discovery, which could potentially surpass the size of the Qasr field in Egypt, will be further appraised in 2008 in order to begin work on a development plan.

Apache is also the beneficiary of strong demand for Carnarvon basin natural gas where industry prices have recently risen to a multiple of Apache s Australian $1.89 per Mcf average price in 2007. Apache is currently in the tender process for its gas from the Reindeer field and expects to complete negotiations during 2008 on initial contracts. Apache also anticipates tendering Julimar gas to market in 2008.

Apache entered the North Sea in 2003 acquiring an approximately 97 percent working interest in the Forties field (Forties), the largest field ever discovered in the U.K. Production decreased eight percent in 2007 but was still well ahead of our 28,800 b/d proved acquisition forecast. Production was impacted by suspension of drilling on the Alpha and Echo platforms for facility upgrades. We plan an active 15-well program in 2008 which is forecasted to increase production over 2007. We will also drill two exploration wells and one appraisal well on blocks outside Forties. 2008 will also mark the completion of a number of key facility projects such as installation of new gas lift compression equipment on both the Alpha and Delta platforms and new produced water handling and reinjection facility on Charlie, as well as an enhanced crude oil import-export header system designed to significantly impact the reliability and operating efficiency of the field.

For several years we held small interests in Argentina with a long-term view of expanding there through acquisitions. In April 2006, we purchased Pioneer Natural Resources (Pioneer) interests in Neuquén and the Austral basins and in September 2006 purchased our partner s, Pan American Fueguina S.R.L. (Pan American), interests in Tierra del Fuego (TdF), gaining operatorship in the under-exploited, highly prospective Austral basin concessions. 2007 was a year of significant accomplishments. We increased production on the acquired properties through a successful drilling and development program and have established Argentina as Apache s latest core area. We made the first significant oil discovery from our 3-D seismic work in TdF which came online producing approximately 1,600 b/d and 1.3 MMcf/d. We were able to increase our gas price over 20 percent from 2006 with the prospect of signing more spot contracts for around $3.00 per Mcf. 2007 was not without its challenges as the government placed a ceiling on oil prices in the fourth quarter that effectively caps our oil price at $42.00 per barrel when the WTI price is $60.90 or greater. In TdF, the price cap applies but Apache retains the 21 percent Value Added Tax collected from buyers, effectively increasing realized prices. While Argentina presents unique challenges with evolving governmental regulations, we are optimistic about our ability to find additional hydrocarbons with the drill bit and growing our reserves and production over the long-term.

Operating Highlights

We currently have production in six countries: the United States (Gulf Coast and Central regions), Canada, Egypt, Australia, offshore the United Kingdom in the North Sea and Argentina. We are finalizing contracts for two exploration blocks in Chile.

The following table sets out a brief comparative summary of certain key 2007 data for each area. Each country s production and average sales prices for 2007, 2006, and 2005 are in this section under Production, Pricing and Lease Operating Cost Data. See also Item 7 Management s Discussion and Analysis of Financial Condition, Note 12 Supplemental Oil and Gas Disclosures (Unaudited) and Note 11 Business Segment Information of this Form 10-K.

	2007 Production (In MMboe)	Percentage of Total 2007 Production	2007 Production Revenue (In millions)	12/31/07 Estimated Proved Reserves (In MMboe)	Percentage of Total Estimated Proved Reserves	2007 Gross New Wells Drilled	2007 Gross New Productive Wells Drilled
Region/Country:							
Gulf Coast	50.7	24.8%	$ 2,737	365.1	14.9%	84	65
Central	32.0	15.6	1,569	636.3	26.0	343	335
Total U.S.	82.7	40.4	4,306	1,001.4	40.9	427	400
Canada	31.3	15.3	1,393	566.9	23.2	348	287
Total North America	114.0	55.7	5,699	1,568.3	64.1	775	687
Egypt	36.8	18.0	2,012	291.7	11.9	192	161
Australia	16.9	8.3	536	268.0	11.0	24	10
North Sea	19.7	9.6	1,399	205.8	8.4	16	5
Argentina	17.4	8.4	316	112.0	4.6	94	92
Total International	90.8	44.3	4,263	877.5	35.9	326	268
Total	204.8	100.0%	$ 9,962	2,445.8	100.0%	1,101	955

The following discussions include references to our plans for 2008. These only represent initial estimates and could vary significantly from actual results. During the year, we routinely adjust our level of spending based on results and changing industry conditions.

United States

Gulf Coast The Gulf Coast 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 holder and the second largest producer in Gulf waters less than 1,200 feet deep since 2004. For the ninth consecutive year, the Gulf Coast was our leading region for both production volumes and revenues. In 2007 the region contributed close to 25 percent of our production and 27 percent of our revenues. Gulf Coast activities in 2007 focused on an active drilling program, completing 65 out of 84 total wells drilled as producers, and restoring production impacted by the 2005 hurricanes. This region performed 233 workover and recompletion operations during 2007. At year-end 2007, the Gulf Coast region accounted for approximately 15 percent of our estimated proved reserves. Although actual annual capital expenditures may change considerably in 2008, we currently estimate investing approximately $900 million on drilling, recompletions, equipment upgrades, production enhancement projects and seismic. In addition, we plan to spend an estimated $400 million on plugging and abandonment work, including $250 million associated with damage caused by Hurricanes Katrina and Rita in 2005.

Central The Central region includes assets in East Texas, the Permian basin of West Texas and New Mexico, and the Anadarko basin of western Oklahoma and the Texas Panhandle, where the Company got its start over 50 years ago. In early 2007, we acquired an additional $1 billion of producing properties in the Permian basin. At year-end 2007, the Central region accounted for approximately 26 percent of our estimated proved reserves, the largest concentration in the Company. During 2007, we participated in drilling 343 wells, 335 of which were completed as productive. Apache also performed 994 workovers and recompletions in the region during the year. We currently estimate spending approximately $660 million in 2008 on drilling, recompletions and production enhancement projects.

Marketing In general, most of our U.S. gas is sold based on either monthly or daily market prices. Our natural gas is sold primarily to Local Distribution Companies (LDCs), utilities, end-users, integrated major oil and gas companies and marketers. Approximately five percent of our 2007 U.S. natural gas production was sold under long-term fixed-price physical contracts which expire in 2008. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk Commodity Risk in this Form 10-K.

Apache primarily markets its U.S. crude oil to integrated major oil companies, purchasers, transporters, and refiners. The objective is to maximize the value of the crude oil sold by identifying the best markets and most economical transportation routes available to move the crude oil. Sales contracts are generally 30-day evergreen contracts and renew automatically until canceled by either party. These contracts provide for sales that are priced daily at market prevailing prices. In 2007, we entered several multi-month contracts in order to reduce the transportation cost component of these contracts.

We manage our credit risk by selling our oil and gas to creditworthy counterparties and monitoring our exposure on a daily basis.

Canada

Overview Our exploration and development activity in our Canadian region is concentrated in the provinces of Alberta, British Columbia, Saskatchewan and to a minor degree the Northwest Territories. The region comprises 23 percent of our estimated proved reserves, the second largest in the Company. We hold five million net acres in Canada, the largest of our North American regions. This year we drilled 348 wells with 287 completed as producers. Exploration wells comprised 9 percent of the net wells drilled, up from six percent in 2006. We performed 478 workover and recompletion projects. We currently estimate spending approximately $600 million in 2008 to drill 394 wells. Our 2008 drilling program will include 358 low-risk development wells and 36 higher risk, higher potential exploration wells in NEBC and Alberta.

Apache continues to target shallow gas including coal bed methane (CBM) in fields such as Provost and Nevis and through these efforts has emerged as one of Canada s largest producers of CBM. The North and South Grant Lands obtained through farm-in agreements discussed below provide additional CBM potential. Also in 2008 we will continue our pursuit of the emerging shale gas play in NEBC, where we have now acquired over 200,000 highly prospective net acres, with a nine well winter drilling program.

Apache signed farm-in agreements in 2004 and 2005 with ExxonMobil covering over one million acres of undeveloped properties in the province of Alberta. Under the agreements, Apache drilled to earn an interest in the land while ExxonMobil retained a royalty on fee lands and a convertible working interest on leasehold acreage. Through the end of 2007, Apache had drilled a total of 751 wells on the farm-in acreage from both agreements.

Marketing Our Canadian natural gas sales focuses on sales to LDCs, utilities, end-users, integrated majors, supply aggregators and marketers. Our composite client portfolio is creditworthy and diverse. Improved North American natural gas pipeline connectivity has triggered a closer correlation between Canadian and U.S. natural gas prices. To diversify our market exposure and optimize pricing differences in the U.S. and Canada, we transport natural gas via our firm transportation contracts to California, the Chicago area, and eastern Canada. Our objective is to sell the majority of our production monthly, either into the first of the month market, or the daily market. In 2007, approximately two percent of our gas sales were subject to long-term fixed-price contracts, the longest of which expires in 2011.

Our Canadian crude oil is primarily sold to refiners, integrated majors and marketers. To increase the market value of our condensate and heavier crudes, our condensate is either used or sold for blending purposes. We sell our oil and natural gas liquids (NGLs) on crude oil postings, which are market reflective prices that depend on worldwide crude oil prices and are adjusted for transportation and quality. In order to reach more purchasers and diversify our market, we transport crude on 12 pipelines to the major trading hubs within Alberta and Saskatchewan.

Egypt

Overview 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. Apache is the largest acreage holder and the most active driller in Egypt. Egypt holds our largest acreage position with approximately 18.9 million gross acres in 23 separate concessions (19 producing concessions) as of December 31, 2007. Development leases within concessions generally have a 25-year life with extensions possible for additional commercial discoveries, or on a negotiated basis. Apache is the largest producer of liquid hydrocarbons and natural gas in the Western Desert and third largest in all of Egypt. Egypt contributed 20 percent of Apache s production revenues and 18 percent of total production in 2007 and approximately 12 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 2007, Apache had an active drilling program in Egypt, completing 161 of 192 wells, an 84 percent success rate, and conducted 450 workovers and recompletions. We currently plan to spend approximately $1 billion in 2008; $700 million on drilling nearly 300 wells, recompletions and production enhancement projects and $300 million on gathering, transmission and processing facility projects. In 2006 we received approval to expand our Western Desert gas processing capacity and infrastructure to process an additional 200 MMcf/d primarily from the Qasr field discovery. Work commenced in 2007 and we expect incremental production from the expansion to begin late in the fourth quarter of 2008.

Marketing Our gas production is sold to EGPC 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, the 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.

Oil from the Khalda Concession, the Qarun Concession and other nearby Western Desert blocks is either sold directly to EGPC or other third-parties. Oil sales are made either directly into the Egyptian oil pipeline grid, exported via one of two terminals on the north coast of Egypt, or sold to third parties (non-governmental) through the MIDOR refinery located in northern Egypt. Oil production that is presently sold to EGPC is sold on a spot basis at a Western Desert price (indexed to Brent). In 2007, we exported 32 cargoes (approximately 9.8 million barrels) of Western Desert crude oil from the El Hamra and Sidi Kerir terminals located on the northern coast of Egypt. These export cargoes were sold at market prices at or above our domestic sales to EGPC. Additionally, 28 cargoes representing 3.7 million barrels were sold in Egypt to other non-governmental purchasers at prevailing market prices. We expect export sales from both the Khalda and Qarun areas in the Western Desert will continue in 2008.

Australia

Overview Our exploration activity in Australia is focused in the offshore Carnarvon, Gippsland and Browse basins where Apache holds 5.4 million net acres in 31 Exploration Permits, 10 Production Licenses, and 5 Retention Leases. Production operations are concentrated in the Carnarvon basin, the location of all 10 Production Licenses, all of which are operated by Apache. In 2007, the region generated $536 million of production revenues from 16.9 MMboe, approximately eight percent of our total production, and accounted for 11 percent of our year-end estimated proved reserves. During the year we participated in drilling 24 wells; generating eight productive gas wells and two productive oil wells.

During 2008, our Australian region plans to increase its exploration, appraisal and field development activities. Twenty-four exploration wells are expected to be drilled in 2008, targeting gas opportunities in the highly prospective

Julimar-Brunello area, in the Carnarvon basin and prospects in the Gippsland basin, which targets both oil and gas opportunities. Two new development projects were sanctioned in 2007. Van Gogh, operated by Apache, is an oil discovery in the Exmouth basin that will be produced through a Floating Production Storage and Offloading tanker (FPSO) beginning in early 2009 with Apache s share estimated at 20,000 b/d. We plan to drill 13 wells in the Van Gogh field in 2008 while work progresses on the FPSO and subsea components. Pyrenees, the second project and also in the Exmouth basin, is operated by BHP Billiton (BHP). This field will also be produced through an

FPSO and should commence production in 2010 at an estimated 20,000 b/d net to Apache. Work will continue on the Reindeer gas discovery in the Carnarvon basin, with gas to be piped to shore for processing at a new gas plant located at Devil s Creek beginning in 2010. Two development wells are planned for the field in 2008.

In 2008, we currently estimate spending approximately $550 million on 48 wells and production enhancement projects and another $350 million on new development facilities at Van Gogh, Pyrenees and Reindeer.

Marketing As of December 31, 2007, Apache had a total of 21 active gas contracts with expiration dates ranging from July 2008 to July 2030. Generally, natural gas is sold in Western Australia under long-term, fixed-price contracts, many of which contain price escalation clauses based on the Australian consumer price index.

We continue to export all of our crude oil production into international markets at prices indexed to Asian benchmark crudes which typically track at or above NYMEX WTI prices.

North Sea

Overview In 2007, the North Sea region produced 19.7 MMboe, generating $1.4 billion of revenue. We continued to develop our North Sea core area around the Forties field, including investments in upgrades to improve the operating efficiency of our platforms. In the Forties field, we commissioned a number of key facility projects, including new power generation and multi-platform gas and power distribution systems, export pumping, produced water handling and injection systems and drilling rig package upgrades.

These efforts have already shown to be successful as operating efficiencies improved 11 percent relative to 2006. Despite an improvement in topsides efficiency, 2007 production was down eight percent from 2006. Workovers to restore production on the Echo platform progressed slower than planned, and new drilling was postponed on the Alpha platform to complete facility upgrades. Production from each of the other three platforms in the field (Bravo, Charlie, and Delta) increased in 2007 compared to 2006.

In 2007 we invested $538 million of capital in the North Sea region, including investments in drilling, recompletion and facility upgrades. The region drilled 16 wells in 2007, five of which were productive. Three exploration wells were drilled outside Forties but did not find commercial hydrocarbon accumulations. Also during 2007, a seismic survey acquired over Forties in 2005 was reprocessed to identify bypassed oil in the main reservoir units and enabled us to update the inventory of future drilling targets.

North Sea capital expenditures for 2008 are currently estimated at $500 million. In Forties, we will continue the development drilling program with 15 new wells planned and completion of several platform facility upgrades initiated last year. The upgrades for 2008 include finalizing the installation of a produced water handling and re-injection system on the Charlie platform, new gas lift compression systems on Alpha and Delta, replacement of glycol dehydration systems and upgrades to lower voltage electrical systems. Outside Forties, at least one appraisal and two exploration wells are planned to be drilled during the year.

Marketing In 2007, we entered into one new term contract for the physical sale of Forties crude at prevailing market prices, which are composed of base market indices, adjusted for the quality difference between the Forties crude and Brent and a premium to reflect the higher market value for term arrangements. In 2006, a new value adjustment formula (Quality Bank Adjustment) was implemented in BP s Forties Pipeline System, through which Forties crude is shipped and commingled with crudes from other central North Sea fields. The new agreed upon formula better represents Apache s crude value in the Forties Pipeline System.

Argentina

Argentina became our latest core area following two significant acquisitions in 2006 that substantially increased our presence in the country. In the second quarter of 2006, we completed our purchase of Pioneer s operations in Argentina for $675 million, with estimated proved reserves of 22 MMbbls of liquid hydrocarbons and 297 Bcf of natural gas. In the third quarter of 2006, we acquired additional interests in (and now operate) seven concessions in Tierra del Fuego from Pan American for total consideration of $429 million. Our oil and gas assets are located in the Neuquén, San Jorge and Austral basins of Argentina. In 2007, we recorded 17.4 MMboe of production and at year end had 112.0 MMboe of estimated proved reserves, approximately eight percent and five percent, respectively, of Apache s total production and reserves.

In 2007 Apache completed over 1,700 square kilometers of a nearly 2,500 square kilometer 3D seismic mega shoot in Tierra del Fuego. The program will be completed in 2008.

On the mainland, we established the commerciality of two gas areas in the Neuquén Basin, each operated by Apache with a 100 percent working interest. In the Anticlinal Campamento block, Apache completed five Pre Cuyo Deep Gas wells. In our Estacion Fernandez Oro block we completed four wells and established commerciality of the Deep Lajas gas play. We are encouraged by the results and foresee the potential of 150 new drilling locations.

In Tierra del Fuego, Apache made two significant discoveries on operated blocks in which we own a 70 percent working interest. In our Cabo Nombre Sur area, we drilled two wells directionally into a new reservoir structure. In our Seccion Banos area, we discovered a new field between two mature fields five miles apart. We believe we have sufficient drilling locations to utilize our shallow rig for the remainder of 2008 and are evaluating mobilizing another rig to the province.

In total, the region drilled 94 wells, 92 of which were productive. In 2008, Apache plans to invest $250 million drilling 100 wells and performing recompletion activities. The region also plans to invest an additional $40 million on waterfloods and expanded production facilities.

Marketing In Argentina, we receive low government-regulated pricing on a substantial portion of our gas production. The volumes we are required to sell at regulated prices are set by the government and vary with seasonal factors and industry category. We extended our exisiting natural gas contracts to regulated markets through year-end 2011, per the Argentine Secretary of Energy s request. We also entered into three new term gas contracts up to five years in duration for volume up to 35 MMcf/d. During the year, we realized an average price of $.76 per Mcf on government-regulated sales. The majority of the remaining volumes were sold at market-driven prices, in excess of $2.00 per Mcf at year-end.

In October 2006, the Argentine government removed the export tax exempt status previously afforded the province of Tierra del Fuego through a Special Customs area exemption. The government further assessed an export tax on all gas exports from Argentina based upon the price paid for natural gas imports from Bolivia. This tax reduced the value we receive under our contract with Methanex in Chile, however, we entered into an interim agreement with Methanex to mitigate the effects of this tax. Subsequent to the interim agreement, the Government of Argentina prohibited further gas exports to Methanex. Apache notified Methanex in June 2007 of the existence of force majeure, which continues to prevent deliveries of gas pursuant to the Methanex contract. The Methanex contract represents less than 10 percent of our gas sales in Argentina.

We are currently selling our oil in the domestic market. The government imposed a sliding-scale tax on oil exports which effectively limits the amount we are able to receive in the domestic market to a parity price equivalent to the price of exported crude oil after adjusting for the export taxes. Effective November 19, 2007, the export tax regulations were further modified and now include a cap of $42.00 per barrel when WTI is $60.90 or greater. In TdF, the price cap applies but Apache retains the 21 percent Value Added Tax collected from buyers, effectively increasing realized prices.

Chile

In November 2007, Apache was awarded the exploration rights on two blocks comprising one million net acres in Tierra del Fuego at a bid round. This acreage is adjacent to our 552,000 net acres on the Argentinean side of Tierra del

Fuego and represents a natural extension of our expanding exploration and production operations. Apache is finalizing the contracts with the Chilean government and plans to shoot 3-D seismic in 2008.

Subsequent Events

In January 2008, Apache, BP plc and Chevron Corporation entered into a contract with Well Control, Inc. to decommission downed platforms and related well facilities located offshore Louisiana in the Gulf of Mexico for a fixed fee of $750 million. Apache s portion is 37.5 percent.

On January 29, 2008, the Company completed the sale of its 50 percent 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 properties in the Permian basin of West Texas and New Mexico to Vanguard Permian, LLC for $78 million.

On February 14, 2008, Apache s Board of Directors declared a special cash dividend of 10 cents per common share payable on March 18, 2008, to stockholders of record on February 26, 2008. The regular dividend on the common shares is payable on May 22, 2008, to stockholders of record on April 22, 2008, at the rate of 15 cents per share.

On February 28, 2008, nine days of the 10-day requirement for the $108 threshold of the Company s 2005 Share Appreciation Plan have been met and 14 trading days remain in the current 30-day period. This plan provides incentives for employees to double Apache s share price to $108 by the end of 2008. See Note 7 Capital Stock of Item 15 in this Form 10-K.

Drilling Statistics

Worldwide, in 2007, we participated in drilling 1,101 gross wells, with 955 (87 percent) completed as producers. We also performed more than 4,048 workovers and recompletions during the year. Historically, our drilling activities in the U.S. generally concentrate 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: 62 in the U.S. (28.49 net); 14 in Canada (13.69 net); 29 in Egypt (27.95 net); three in Australia (2.17 net); one in the North Sea (0.98 net); and 17 in Argentina (16.4 net).

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

	Net Exploratory			Net Development			Total Net Wells		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
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
2006									
United States	2.9	2.7	5.6	266.4	15.3	281.7	269.3	18.0	287.3
Canada	34.3	6.4	40.7	577.3	114.8	692.1	611.6	121.2	732.8
Egypt	11.8	8.9	20.7	122.7	10.4	133.1	134.5	19.4	153.9
Australia	1.2	9.3	10.5	1.0	1.3	2.3	2.2	10.6	12.8
North Sea		1.0	1.0	3.9		3.9	3.9	1.0	4.9
Argentina	9.3	5.3	14.6	60.8	2.0	62.8	70.1	7.3	77.4
Other International				1.5		1.5	1.5		1.5
Total	59.5	33.6	93.1	1,033.6	143.8	1,177.4	1,093.1	177.5	1,270.6
2005									
United States	5.0	3.1	8.1	248.8	24.1	272.9	253.8	27.2	281.0
Canada	273.4	107.6	381.0	1,057.0		1,057.0	1,330.4	107.6	1,438.0
Egypt	17.8	6.9	24.7	79.4	7.1	86.5	97.2	14.0	111.2
Australia	.7	6.8	7.5	11.8	4.8	16.6	12.5	11.6	24.1
North Sea		7.8	7.8	12.6	1.9	14.5	12.6	9.7	22.3
Argentina	6.3	3.0	9.3	15.6	1.0	16.6	21.9	4.0	25.9
Other International				3.7	.2	3.9	3.7	.2	3.9
Total	303.2	135.2	438.4	1,428.9	39.1	1,468.0	1,732.1	174.3	1,906.4

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, 2007, is set forth below:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net

Gulf Coast	1,024	791	1,073	751	2,097	1,542
Central	3,259	1,683	7,536	5,109	10,795	6,792
Canada	8,255	7,125	2,465	1,006	10,720	8,131
Egypt	36	36	500	477	536	513
Australia	12	8	30	18	42	26
North Sea			60	58	60	58
Argentina	360	323	540	475	900	798
Total	12,946	9,966	12,204	7,894	25,150	17,860

Production, Pricing and Lease Operating Cost Data

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

	Production			Average Lease Operating Cost per Boe	Average Sales Price		
Year Ended December 31,	Oil (Mbbls)	NGLs (Mbbls)	Gas (MMcf)		Oil (Per bbl)	NGLs (Per bbl)	Gas (Per Mcf)
2007							
United States	33,127	2,811	280,903	$ 11.99	$ 66.48	$ 45.24	$ 7.04
Canada	6,846	820	141,697	12.74	68.29	40.55	6.30
Egypt	22,168		87,883	5.16	72.51		4.60
Australia	5,029		71,149	6.15	79.79		1.89
North Sea	19,576		705	28.21	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	$ 11.35	$ 68.84	$ 42.78	$ 5.34
2006							
United States	24,394	2,915	243,442	$ 11.13	$ 54.22	$ 38.44	$ 6.54
Canada	7,561	798	147,579	10.58	59.90	35.40	6.09
Egypt	20,648		79,424	4.68	63.60		4.42
Australia	4,341		67,933	4.95	68.25		1.65
North Sea	21,368		752	28.23	63.04		10.64
Argentina	2,503	561	40,878	4.47	42.79	36.64	.99
Other International	1,156			4.77	62.73		
Total	81,971	4,274	580,008	$ 10.92	$ 59.92	$ 37.70	$ 5.17
2005							
United States	24,188	2,757	218,081	$ 9.59	$ 47.97	$ 32.44	$ 7.22
Canada	8,212	816	135,750	8.59	53.05	31.07	7.29
Egypt	20,126		60,484	4.11	53.69		4.59
Australia	5,613		45,003	7.17	57.61		1.72
North Sea	23,903		842	19.11	53.00		9.17
Argentina	424		1,137	6.54	37.54		1.14
Other International	2,968			4.05	44.24		
Total	85,434	3,573	461,297	$ 9.48	$ 51.66	$ 32.13	$ 6.35

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	2,054,649	1,288,225	2,961,420	1,830,841
Canada	3,262,233	2,295,888	3,564,548	2,776,462
Egypt	17,459,238	10,399,793	1,429,063	1,302,208
Australia	7,122,380	5,095,020	527,450	316,480
North Sea	689,229	538,835	29,924	29,174
Argentina	2,192,000	1,913,000	260,000	196,000
Total Company	32,779,729	21,530,761	8,772,405	6,451,165

As of December 31, 2007, we had 4,294,752, 1,868,688 and 4,803,317 net acres scheduled to expire by December 31, 2008, 2009 and 2010, 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.

Estimated Proved Reserves and Future Net Cash Flows

As of December 31, 2007, Apache had total estimated proved reserves of 1,134 MMbbls of crude oil, condensate and NGLs and 7.9 Tcf of natural gas. Combined, these total estimated proved reserves are equivalent to 2.4 billion barrels of oil equivalent or 14.7 Tcf of natural gas. During 2007, the Company s reserves grew six percent, the 22nd consecutive annual increase.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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 economical productivity is 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 in the reservoir provides support for the engineering analysis on which the project or program is based. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

Apache emphasizes that its reported reserves are estimates which, by their nature, are subject to revision. The estimates are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed throughout the year, and revised either upward or downward, as warranted by additional performance data.

Apache s proved reserves are estimated at the property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who are 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. 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.

The estimate of reserves disclosed in this Annual Report on Form 10-K are prepared by the Company s internal staff and the Company is responsible for the adequacy and accuracy of those estimates. However, we engage 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. We selected the properties for review by Ryder Scott and these properties represented all material fields, approximately 88 percent of international properties and over 80 percent of each country s reserve value for new wells drilled during the year. During 2007, 2006 and 2005, Ryder Scott s review covered 77, 75 and 74 percent of the Company s worldwide estimated reserves value, respectively.

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 their tests and procedures used during their 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.

The Company s estimates of proved reserves and proved developed reserves as of December 31, 2007, 2006 and 2005, changes in estimated proved reserves during the last three years, and estimates of future net cash flows and discounted future net cash flows from estimated proved reserves are contained in Note 12 - Supplemental Oil and Gas Disclosures of Item 15 in this Form 10-K. These estimated future net cash flows are based on prices on the last day of the year and are calculated in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, Disclosures about Oil and Gas Producing Activities. Disclosure of this value and related reserves has been prepared in accordance with SEC Regulation S-X Rule 4-10.

Employees

On December 31, 2007, we had 3,521 employees. Only 24 of these employees are subject to collective bargaining agreements, all of whom are in Argentina.

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 2007, we maintained regional exploration and/or production offices in 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, see the table in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, Capital Resources and Liquidity, and Note 9 Commitments and Contingencies of Item 15 in this Form 10-K.

Title to Interests

As is customary in our industry, a preliminary review of title records is made at the time we acquire properties, which may include opinions or reports of appropriate professionals or counsel. 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 which 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, and 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.

Our profitability is highly dependent on the prices of crude oil, natural gas and natural gas liquids, which have historically been very volatile

Our estimated proved reserves, revenues, profitability, operating cash flows and future rate of growth are highly dependent on the prices of crude oil, natural gas and NGLs, which are affected by numerous factors beyond our control. Historically, these prices have been very volatile, and are likely to remain volatile in the future. A significant and extended downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow, and could result in a reduction in the carrying value of our oil and gas properties and the amounts of our estimated proved oil and gas reserves. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas prices adversely affects our financial position.

Our commodity hedging may prevent us from benefiting fully from price increases and may expose us to other risks

To the extent that we engage in hedging activities to protect ourselves from commodity price declines, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

Hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or the counterparties to our future contracts fail to perform under the contracts. We cannot assure that our hedging transactions will reduce the risk or minimize the effect of any decline in crude oil or natural gas prices.

Acquisitions or discoveries 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 due to 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.

Inherent risk in drilling

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.

Certain 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.

Risks arising from the failure to fully identify potential problems related to acquired reserves or to properly estimate those reserves

Although we perform a review of the acquired properties that we believe is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water 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 actual 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.

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.

International operations have uncertain political, economic and other risks

Our operations outside North America are based primarily in Egypt, Australia, the United Kingdom and Argentina. On a barrel equivalent basis, approximately 44 percent of our 2007 production was outside North America and approximately 36 percent of our estimated proved oil and gas reserves on December 31, 2007 were located outside North America. As a result, we face political and economic risks and other uncertainties that are more prevalent than our North American operations. Such factors include, but are not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation, 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 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 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 investment. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned 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.

On December 23, 2004, Apache entered into a 20-year insurance contract with the Overseas Private Investment Corporation (OPIC) which provides $300 million of political risk insurance for the Company s Egyptian operations. This policy insures us against (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum when actions taken by the Government of Egypt prevent Apache from exporting our share of production.

The Company also purchases multi-year commercial political risk insurance contracts from highly rated international insurers covering portions of its investments in Egypt and Argentina. The insurance provides coverage for confiscation, nationalization, and expropriation risks and currency inconvertibility. Effective March 23, 2007, the Company entered into an additional multi-year insurance contract with OPIC to provide $200 million of coverage for Egypt in excess of the commercial insurance program.

We have limited control over the activities on properties we do not operate

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

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 estimate and actual timing of critical events may adversely affect our forward looking statements related to large development projects, and our ability to participate in large scale development projects in the future.

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 with 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 exchanges rates may adversely affect our results of operation, particularly by a weakening U.S. dollar relative to other currencies.

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

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impacts 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. While our planning for normal climatic variation, insurance program, and emergency recovery plans mitigate the effects of the weather, not all such effects can be predicted, eliminated or insured against.

Costs incurred related to environmental matters

We, as an owner or lessee and operator of oil and gas properties, 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.

We have made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry. We have established policies for continuing compliance with environmental laws and regulations, including regulations applicable to our operations in all countries in which we do business. We also have established operational procedures and training programs designed to minimize the environmental impact of our field facilities. Apache manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The costs incurred by these policies and procedures are inextricably connected to normal operating expenses such that we are unable to separate the expenses related to environmental matters; however, we do not believe any such additional expenses are material to our financial position or results of operations.

The Company also conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of our employees who are expected to devote a significant amount of time to any possible remediation effort. Our general policy is to limit any reserve additions to incidents or sites that are considered probable to result in an expected remediation cost exceeding $300,000.

We maintain insurance coverage, which we believe is customary in the industry, although we are not fully insured against all environmental risks. As described in Note 9 Commitments and Contingencies of Item 15, in this Form 10-K, on December 31, 2007, we had an accrued liability of $28 million for environmental remediation. We have not incurred any material environmental remediation costs in any of the periods presented and we are not aware of any future environmental remediation matters that would be material to our financial position or results of operations.

Although environmental requirements have a substantial impact upon the energy industry, generally these requirements do not appear to affect us any differently, or to any greater or lesser extent, than other upstream companies in the industry. We do not believe that compliance with federal, provincial, state, local or foreign country provisions regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, will have a material adverse effect upon the capital expenditures, earnings or competitive position of Apache or its subsidiaries; however, there is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not have such an impact.

Industry competition

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 the marketing of oil and natural gas production. Higher recent crude oil and natural gas prices have increased 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 changing worldwide 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, geo-physicists, engineers and other specialists.

Insurance does not cover all risks

Exploration for and production of oil and natural gas can be hazardous, involving unforeseen occurrences such as blowouts, cratering, fires 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 or the environment. We maintain insurance against certain losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that management believes to be prudent; however, insurance is not available to us against all operational risks.

ITEM 1B. *UNRESOLVED SEC STAFF COMMENTS*

As of December 31, 2007, 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*

See the information set forth in Note 9 Commitments and Contingencies of Item 15.

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 2007, 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 2007 and 2006. 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.

	2007				2006			
	Price Range		Dividends per Share		Price Range		Dividends per Share	
	High	Low	Declared	Paid	High	Low	Declared	Paid
First Quarter	$ 73.44	$ 63.01	$ .15	$ .15	$ 76.25	$ 63.17	$ .10	$ .10
Second Quarter	87.82	70.53	.15	.15	75.66	56.50	.10	.10

Third Quarter	91.25	73.41	.15	.15	72.40	59.18	.15	.10
Fourth Quarter	109.32	87.44	.15	.15	70.50	59.99	.15	.15

The closing price per share of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2008, was $95.36. On January 31, 2008, there were 332,991,134 shares of our common stock outstanding held by approximately 7,000 shareholders of record and approximately 363,000 beneficial owners.

We have paid cash dividends on our common stock for 43 consecutive years through December 31, 2007. 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 and, the rights trade automatically with our shares of common stock. For a description of the rights, please refer to Note 7 Capital Stock of Item 15 in 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 2008 annual meeting of stockholders, which is incorporated herein by reference.

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, 2002 through December 31, 2007.

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

* $100 invested on 12/31/02 in stock including reinvestment of dividends.
Fiscal year ending December 31.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Apache Corporation	$ 100.00	$ 150.40	$ 188.61	$ 257.04	$ 251.12	$ 409.11
S & P s Composite 500 Stock Index	100.00	128.68	142.69	149.70	173.34	182.86
DJ US Expl & Prod Index	100.00	131.06	185.94	307.40	323.91	465.35

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, 2007, 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 of Item 15 in this Form 10-K.

	As of or for the Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In thousands, except per share amounts)				
Income Statement Data					
Total revenues	$ 9,977,858	$ 8,288,779	$ 7,584,244	$ 5,332,577	$ 4,190,299
Income (loss) attributable to common stock	2,806,678	2,546,771	2,618,050	1,663,074	1,116,205
Net income (loss) per common share:					
Basic	8.45	7.72	7.96	5.10	3.46
Diluted	8.39	7.64	7.84	5.03	3.43
Cash dividends declared per common share	.60	.50	.36	.28	.22
Balance Sheet Data					
Total assets	$ 28,634,651	$ 24,308,175	$ 19,271,796	$ 15,502,480	$ 12,416,126
Long-term debt	4,011,605	2,019,831	2,191,954	2,588,390	2,326,966
Shareholders equity	15,377,979	13,191,053	10,541,215	8,204,421	6,532,798
Common shares outstanding	332,927	330,737	330,121	327,458	324,497

For a discussion of significant acquisitions and divestitures, see Note 2 of Item 15 in this Form 10-K.

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

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

Executive Overview

Apache Corporation (Apache or the Company) is one of the largest independent (non-integrated) oil and natural gas upstream companies in the United States (U.S.). At Apache, we strive to generate competitive returns and build a profitable oil and gas company for the long-term benefit of our shareholders using the following strategy:

Build a balanced portfolio of assets which provides a platform for profitable growth through drilling and acquisitions across the cycles of our dynamic industry;

Maintain financial discipline and a strong balance sheet; and

Maximize cash flow and earnings from each unit of production by controlling administrative, operating and capital costs.

A key part of our strategy is balancing our portfolio through diversity of geological risk, political risk, hydrocarbon mix (crude oil versus natural gas) and reserve life in order to achieve consistency in results. Our portfolio of geographic locations provides variation of all of these factors and, additionally, in the case of Australia and Argentina, the potential for increasing the value of our investments through rising natural gas prices. We currently have operations in the United States (Central and Gulf Coast regions), Canada, Egypt, the United Kingdom sector of the North Sea, Australia and Argentina. We are finalizing contracts for two exploration blocks in Chile. Each region has a significant producing asset base as well as large undeveloped acreage positions which provide room for growth. In 2007, no single region contributed more than 26 percent of our production or reserves. We seek to maintain diversity of reserve life, which translates into balance in the timing of returns on our investments. Reserve life (estimated reserves divided by annual production) in our regions ranges from as short as six years to as long as 20 years. By maintaining a balanced hydrocarbon mix, we are protecting against price deterioration in a given product while retaining upside potential through a significant increase in either commodity price. For example, in 2007, oil and liquids provided 47 percent of our production, but 65 percent of our total oil and gas revenues. We were well positioned to realize the benefit of higher oil prices, which significantly outpaced natural gas price increases. At year-end, our estimated proved reserves were also balanced at 54 percent natural gas and 46 percent crude oil and liquids. Additionally, in each region, we have attained a critical mass that supports sustainable lower-risk drilling opportunities, balanced by higher-risk, higher-reward exploration. In 2007, we drilled, or participated in, 1,101 gross wells with an overall 87 percent success rate; 89 percent were developmental and 11 percent exploratory.

We believe our balanced portfolio strategy enhances our ability to deliver long-term production growth, increase proved reserves at a reasonable economic cost and achieve competitive investment rates of return for the benefit of our shareholders. Our management and incentive systems underscore high cash flow and appropriate risk taking to reach or exceed targeted hurdle rates of return on invested capital. These are measured monthly, reviewed with management quarterly and utilized to determine annual performance awards. We review capital allocations, at least quarterly, through a disciplined and focused process of reviewing internally generated drilling prospects, opportunities for tactical acquisitions, land positions with additional drilling prospects or, occasionally, new core areas which could enhance our portfolio. We continue to deliver strong results with 2007 return on capital employed and return on equity of 16 percent and 20 percent, respectively. Also in 2007, we increased reserves for the 22nd consecutive year and production for the 28th of the last 29 years, a testament to our balanced portfolio approach.

We periodically evaluate our properties to determine whether sales of certain assets could provide opportunities to redeploy our capital resources to rebalance our portfolio and enhance prospective returns. As a result of this process, in 2007 we sold non-strategic oil and gas properties located in northwest Louisiana for approximately $56 million and contracted to sell others for approximately $309 million. The assets under contract are expected to close in the first quarter of 2008.

Preserving financial flexibility is key to our overall business philosophy. We ended 2007 with a year-end debt-to-capitalization ratio of 22 percent, despite current year capital investments of $5.8 billion, excluding asset retirement costs. In tightening credit markets, Apache s single-A debt ratings provide a competitive advantage in accessing capital.

The third critical component of our overall strategy is maximization of earnings and cash flow. Both are significantly impacted by commodity prices, our ability to economically add reserves through drilling and acquisitions, and controlling costs to add and produce reserves. Commodity prices fluctuate and are influenced by factors beyond our control, including worldwide supply and demand, political stability and governmental actions and regulations. While historically high prices have increased our oil and gas revenues in 2007, they also led to increased industry competition and consequently rising costs. Drilling, operating and administrative costs continue to increase from both inflationary pressures from higher commodity prices and the weakened U.S. dollar. We have experienced additional cost increases, particularly in the U.S., with higher demand resulting from activity to repair damage caused by the 2005 Gulf of Mexico hurricanes. Increased demand for producing oil and gas properties has also resulted in higher acquisition prices. We closely monitor drilling and acquisition cost trends in each of our core areas relative to product prices and, when appropriate, adjust our capital budgets accordingly. In addition, we actively seek to identify and pursue alternatives to maintain efficient levels of costs and expenses. Despite pressure from rising costs, 2007 pre-tax margins were our second highest on record. We calculate pre-tax margins as follows:

	Pre-tax Margins		
	2007	2006	2005
	(In thousands, except margin)		
Income before Income Taxes	$ 4,672,612	$ 4,009,595	$ 4,206,254
Barrels of oil equivalent produced	204,852	182,913	165,890
Margin per boe produced	$ 22.81	$ 21.92	$ 25.36

Operating Highlights

We made considerable operational progress during the year which we believe adds to our platform for long-term profitable growth. Key operational highlights include:

U.S. Central

Our $1 billion acquisition of producing properties in the Permian basin of West Texas and a successful drilling program contributed to another year of growth with productions and reserves increasing 17 and 15 percent, respectively. These acquired properties had an estimated 70 MMboe at the end of 2006 and compliment our existing long-lived Permian basin assets.

U.S. Gulf Coast

In September 2007, we executed a farm-in agreement securing exploration and development opportunities in deep rights below the Austin chalk on approximately 400,000 net acres.

Our Gulf Coast region increased daily equivalent production 25 percent upon restoration of final production outages from Hurricanes Katrina and Rita, successful drilling and recompletion programs and a full year of production from properties acquired in June 2006.

Canada

We drilled and tested one horizontal well and conducted long-term production tests on two vertical wells in our Ootla shale gas play in British Columbia. Encouraged by our results, we acquired additional acreage in the play during the year, bringing our total position to 400,000 gross (200,000 net) acres.

Egypt

We doubled our acreage position with a 50 percent interest in four new concessions, adding 10.5 million gross acres of exploration potential. Progress is being made on our Salam gas plant expansion, which should be completed by the end of 2008, adding approximately 90 to 100 million cubic feet per day (MMcf/d) and 4,500 barrels per day (b/d) of capacity net to Apache. We also continued expansion of several waterflood projects with further drilling and increased water injection capacity.

Australia

In 2007 we announced discoveries in the Julimar, Julimar East and Brunello fields on Australia s Northwest Shelf. The discovery which could potentially be the largest field ever found by Apache, will be further appraised in 2008. We own a 65 percent working interest in the Julimar-Brunello complex.

The Pyrenees development, operated by BHP Billiton (BHP), was sanctioned in 2007. Construction will begin in 2008 with development drilling to start in early 2009. This project is expected to commence production in early 2010 at an estimated net rate of 20,000 b/d.

We executed a contract for a Floating Production Storage and Offloading vessel (FPSO) that will be used in the $500 million Van Gogh development in Western Australia s Exmouth Basin. We own 52.5 percent of the development, which was sanctioned in 2007. Production is expected to come online in 2009, adding an estimated 20,000 b/d to our net production.

We sanctioned the construction of a pipeline and an onshore natural gas processing plant for our Reindeer gas project in 2007. The field is slated to begin producing in the middle of 2010 at an estimated net rate of 60 MMcf/d.

In 2007 our average realized gas price increased 15 percent, or $.24 per Mcf, with considerable upward pressure on prices of newly contracted gas.

North Sea

Significant investments in platform upgrades continued in 2007. With production averaging almost 54,000 b/d, the Forties remains Apache s largest value field in terms of production, reserves, and cash flow.

Argentina

In 2007 Apache completed 1,700 square kilometers of a nearly 2,500 square kilometer 3-D seismic mega shoot in Tierra del Fuego. The program will be completed in 2008.

In December 2007, Apache announced that the first significant well drilled from a location identified in the three-dimensional seismic survey in Tierra del Fuego began producing at a rate of approximately 1,600 b/d and 1.3 MMcf/d from the Lower Cretaceous Springhill sandstone.

In 2007 our average realized gas price increased 21 percent, up $.20 per Mcf.

Chile

In November 2007, Apache was awarded the exploration rights on two blocks comprising one million net acres in Chile at a bid round. This acreage is adjacent to our 552,000 net acres on the Argentinean side of Tierra del Fuego and represents a natural extension of our expanding exploration and production operations. Apache is finalizing the contracts with the Chilean government and plans to begin shooting 3-D seismic in 2008.

Financial Highlights

In 2007, records were achieved in the key financial measures of earnings, cash flow, revenues, production and year-end estimated reserves. Financial highlights for 2007 relative to 2006 include:

Record earnings of $2.8 billion, up 10 percent.

Record cash provided by operating activities of $5.7 billion, up 32 percent.

Record oil and gas revenues of $10 billion, up 23 percent.

Record production of 561,239 boe per day, up 12 percent.

Record oil prices averaged $68.84 per bbl, up 15 percent; gas prices averaged $5.34 per Mcf, up three percent.

Capital expenditures totaled $5.8 billion; including $4.3 billion for exploration and development (excluding asset retirement obligations), $1 billion for acquisitions and $473 million for gathering, transmission and processing facilities.

Record estimated reserves of 2.4 billion barrels of oil equivalent, up six percent.

Results of Operations

Revenues

	For the Year Ended December 31,					
	2007	Contribution	2006	Contribution	2005	Contribution
Revenues (in thousands):						
Oil	$ 6,259,125	63%	$ 4,911,861	61%	$ 4,413,934	59%
Natural gas	3,503,817	35%	3,001,246	37%	2,928,578	39%
Natural gas liquids	199,040	2%	161,146	2%	114,779	2%
Total	$ 9,961,982	100%	$ 8,074,253	100%	$ 7,457,291	100%

Oil and Natural Gas Prices

Our revenues are sensitive to changes in prices received for our products. A substantial portion of our production is sold at prevailing market prices which fluctuate in response to many factors that are outside of our control. Given the current tightly balanced market, small variations in either supply, demand, or both, can have dramatic effects on prices we receive for our oil and natural gas production. Political instability and availability of alternative fuels could impact worldwide supply, while other economic factors could impact demand.

While the market price received for crude oil and natural gas varies among geographic areas, crude oil trades in a worldwide market. Generally, price movements for all types and grades of crude oil move in the same direction. Apache manages a portion of its exposure to fluctuations in crude oil prices using financial instruments.

In Argentina, we are currently selling our oil in the domestic market. The government imposed a sliding-scale tax on oil exports which effectively limits the amount we are able to receive in the domestic market to a parity price equivalent to the price of exported crude oil after adjusting for export taxes. Effective November 19, 2007, the export tax regulations were further modified and now include a cap of $42.00 per barrel when WTI is $60.90 or greater. In TdF, the price cap applies but Apache retains the 21 percent Value Added Tax collected from buyers, effectively increasing realized prices.

Natural gas, which has a limited global transportation system, is more subject to local supply and demand conditions. The majority of our gas sales contracts are indexed to prevailing local market prices. Apache uses a variety of strategies to manage our exposure to fluctuations in natural gas prices including fixed-price contracts and derivatives.

Apache primarily sells natural gas into four markets:

1) North America, which has a common market and where supply and demand are currently tightly balanced; creating a volatile pricing environment 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 Egyptian General Petroleum Corporation (EGPC) under an industry pricing formula indexed to Dated-Brent crude oil with a maximum price of $2.65 per MMbtu. Apache has retained the

previous gas price formula (without a price cap) until 2013 on up to 100 gross MMcf/d.

3) Australia, which has a local market with mostly long-term fixed-price contracts that are periodically adjusted for changes in Australia s consumer price index.

4) Argentina, where we receive low 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 the year, we realized an average price of $.76 per Mcf on government regulated sales. The majority of the remaining volumes were sold at market-driven prices, in excess of $2.00 per Mcf at year-end.

For specific marketing arrangements by segment, please refer to Item 1 and 2. Business and Properties of this Form 10-K.

Production and Pricing

	For the Year Ended December 31,				
	2007	Increase (Decrease)	2006	Increase (Decrease)	2005
Oil Volume Barrels per day:					
United States	90,759	35.80%	66,832	.85%	66,268
Canada	18,756	(9.46)%	20,715	(7.93)%	22,499
Egypt	60,735	7.36%	56,570	2.59%	55,141
Australia	13,778	15.86%	11,892	(22.67)%	15,379
North Sea	53,632	(8.39)%	58,544	(10.60)%	65,488
Argentina	11,440	66.84%	6,857	NM	1,163
China		NM	3,167	(61.06)%	8,132
Total(1)	249,100	10.92%	224,577	(4.06)%	234,070
Average Oil price Per barrel:					
United States	$ 66.48	22.61%	$ 54.22	13.03%	$ 47.97
Canada	68.29	14.01%	59.90	12.91%	53.05
Egypt	72.51	14.01%	63.60	18.46%	53.69
Australia	79.79	16.91%	68.25	18.47%	57.61
North Sea	70.93	12.52%	63.04	18.94%	53.00
Argentina	45.99	7.48%	42.79	13.99%	37.54
China		NM	62.73	41.79%	44.24
Total(2)	68.84	14.89%	59.92	15.99%	51.66
Natural Gas Volume Mcf per day:					
United States	769,596	15.39%	666,965	11.63%	597,481
Canada	388,211	(3.99)%	404,325	8.71%	371,917
Egypt	240,777	10.65%	217,601	31.31%	165,710
Australia	194,928	4.73%	186,119	50.95%	123,295
North Sea	1,933	(6.21)%	2,061	(10.62)%	2,306
Argentina	200,903	79.39%	111,994	NM	3,114
Total(3)	1,796,348	13.04%	1,589,065	25.73%	1,263,823
Average Natural Gas price Per Mcf:					
United States	$ 7.04	7.65%	$ 6.54	(9.42)%	$ 7.22
Canada	6.30	3.45%	6.09	(16.46)%	7.29
Egypt	4.60	4.07%	4.42	(3.70)%	4.59
Australia	1.89	14.55%	1.65	(4.07)%	1.72
North Sea	15.03	41.26%	10.64	16.03%	9.17
Argentina	1.17	20.62%	.97	(14.91)%	1.14
Total(4)	5.34	3.29%	5.17	(18.58)%	6.35
Natural Gas Liquids (NGL)					

Volume Barrels per day:								
United States		7,702	(3.54)%		7,985	5.72%		7,553
Canada		2,246	2.70%		2,187	(2.15)%		2,235
Argentina		2,800	82.17%		1,537	NM		
Total		12,748	8.87%		11,709	19.63%		9,788
Average NGL Price Per barrel:								
United States	$	45.24	17.38%	$	38.54	18.80%	$	32.44
Canada		40.55	14.55%		35.40	13.94%		31.07
Argentina		37.78	3.11%		36.64	NM		
Total		42.78	13.47%		37.70	17.34%		32.13

(1) Approximately 17 percent of 2007 production was subject to financial derivative hedges, nine percent in 2006 and six percent in 2005.

(2) Reflects per barrel reductions of $1.06 in 2007, $1.37 in 2006 and $.68 in 2005 from financial derivative hedging activities.

(3) Approximately 17 percent of 2007 production was subject to financial derivative hedges, eight percent in 2006 and nine percent in 2005.

(4) Reflects per Mcf increase of $.10 in 2007, reductions of $.05 in 2006 and $.15 in 2005 from financial derivative hedging activities.

NM Not Meaningful

Contributions to Oil and Natural Gas Revenues

The following table presents each country s oil revenues and gas revenues as a percentage of total oil revenues and gas revenues, respectively.

	Oil Revenues For the Year Ended December 31,			Gas Revenues For the Year Ended December 31,		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
United States	35%	27%	26%	56%	53%	54%
Canada	8%	9%	10%	26%	30%	34%
North America	43%	36%	36%	82%	83%	88%
Egypt	26%	27%	25%	12%	12%	9%
Australia	6%	6%	7%	4%	4%	3%
North Sea	22%	27%	29%			
Argentina	3%	2%		2%	1%	
Other International		2%	3%			
Total	100%	100%	100%	100%	100%	100%

Year 2007 Compared to Year 2006

Crude Oil Revenues Apache s 2007 consolidated crude oil revenues totaled $6.3 billion, $1.3 billion above 2006, with nearly equal contributions from an 11 percent rise in production and a 15 percent increase in our realized oil price. On the whole, production increased an average 24,523 barrels per day (b/d), driven by the U.S. which was up 23,927 b/d. Crude oil price realizations averaged $68.84 per barrel for the year, $83.00 in the fourth quarter alone.

U.S. oil revenues were up $879 million to $2.2 billion with $580 million, or two-thirds of the increase, attributable to a 36 percent increase in production. A 23 percent increase in realized prices added the remaining $299 million. Gulf Coast production climbed 48 percent to 53,842 b/d, mainly on production restored from hurricane damaged properties, a full year of production from Gulf of Mexico properties acquired in June 2006 and successful drilling and recompletion activities. Central region production grew 21 percent to 36,917 b/d, with the addition of Permian basin properties acquired from Anadarko Petroleum Corporation (Anadarko) in March 2007 and successful drilling and recompletion activities.

In Egypt, crude oil revenues rose $294 million, to $1.6 billion, with increased production generating an additional $110 million of revenues. The balance of the increase in revenues, $184 million, came from a 14 percent increase in realized prices, which were up $8.91 to $72.51 per barrel. Daily production averaged 60,735 b/d, up seven percent. Production gains were associated with development drilling in the Khalda and Matruh concessions as well as the East Bahariya, Umbarka, El Diyur and North El Diyur concessions.

Australia s crude oil revenues of $401 million increased 35 percent, or $105 million. Production was 16 percent higher generating $55 million of the increase. Production growth resulted from an additional interest acquired in the Legendre field, completion of West Cycad wells, and increased liquids from the Bambra, Wonnich Deep, Doric and Lee gas wells. Australia s price realizations rose 17 percent to $79.79 per barrel, the highest in the Company, generating an additional $50 million of revenue.

Argentina s oil revenues increased $85 million to $192 million, with over 90 percent of the increase associated with 67 percent higher production. The year 2007 benefited from a full year of production from acquisitions made in 2006, as well as successful drilling, workover and recompletion activity during the year. Higher volumes added $77 million to revenues, with price increases adding $8 million. Argentina s realized oil prices averaged $45.99 per barrel, up seven percent from the prior year.

North Sea oil revenues increased $41 million to $1.4 billion. Oil prices averaged $70.93 per barrel, up 13 percent, adding $168 million in revenues. Production averaged 53,632 b/d, down eight percent, reducing revenues by $127 million. Production increases on three of our platforms were more than offset by declines from wells at the Alpha and Echo platforms while drilling operations were postponed for facility upgrades. Drilling operations on the Alpha platform will resume in 2008.

Canada s oil revenues increased $15 million to $467 million, with a 14 percent price increase mostly offset by a nine percent decline in production. Prices averaged $68.29 per barrel, up from $59.90 in 2006. Production dropped in 2007 primarily because of natural decline resulting from a 38 percent reduction in exploration and development capital invested in Canada compared to 2006.

China had no crude oil revenues in 2007 compared to $73 million in the prior year, a result of our August 2006 asset divestiture and exit from China.

Natural Gas Revenues Apache s natural gas revenues increased 17 percent, or $503 million, to $3.5 billion. Higher production contributed $405 million of the additional revenues. Gas production averaged 1,796 MMcf/d, up 13 percent from 2006. Natural gas prices increased $.17 to an average $5.34 per Mcf, generating an additional $98 million in revenue.

U.S. natural gas revenues grew by $385 million to nearly $2 billion. U.S. production rose 15 percent, boosting revenues $264 million. Gulf Coast production increased 16 percent, boosted by final production restoration on hurricane damaged properties, a full year of production from Gulf of Mexico properties acquired in June 2006, and successful drilling and recompletion activities. Central region production climbed 14 percent on successful drilling and recompletion activities and the addition of Permian basin properties acquired in March 2007. Higher natural gas prices, which averaged $7.04 per Mcf compared to $6.54 in 2006, added $121 million to revenues.

Gas revenues in Egypt were up $53 million, to $404 million, on an 11 percent increase in production and a four percent increase in price realizations. Production gains of 23 MMcf/d boosted the region s average output to 241 MMcf/d, generating an additional $39 million in revenues. Production gains resulted from higher throughput and less downtime at the Obaiyed plant compared to 2006 and new wells in the North East Abu Gharadig (NEAG) concession. Higher prices added another $14 million.

Australia s natural gas revenues increased $22 million to $134 million, on higher price realizations and production gains. Price realizations improved 15 percent, adding $16 million to revenues. A five percent demand-driven rise in production generated another $6 million of revenues.

Argentina s natural gas revenues more than doubled to $86 million, bolstered by a full year of production from 2006 property acquisitions, successful drilling and recompletion activities and a 21 percent increase in price realizations. Production grew 89 MMcf/d, or 79 percent, generating $38 million of new revenues. The price gain added another $8 million.

Canada s natural gas revenues decreased $6 million, to $892 million on a four percent decline in production. Production, which averaged 388 MMcf/d, was impacted by natural decline which more than offset increases from drilling and recompletion activities. Our exploration and development capital investment in Canada was 38 percent lower than 2006. Lower production reduced revenues by $37 million. Natural gas prices rose $.21, to $6.30 per Mcf, increasing revenues $31 million.

Year 2006 Compared to Year 2005

Crude Oil Revenues Crude oil revenues in 2006 increased $498 million from 2005 to $4.9 billion. Price gains across all regions, which averaged $8.26 more per barrel than 2005, generated an additional $706 million of revenues. These additional revenues were partially offset by the effect of a four percent decline in production. All segments reported a significant increase in realized crude oil price, with Argentina, Egypt, and the U.S. also benefiting from production growth compared to 2005.

Egypt generated an additional $233 million of crude oil revenue in 2006. An 18 percent increase in crude oil price realizations, generated $200 million of the additional revenues, with the remainder coming from a three percent increase in production. While Egypt experienced production growth in many areas, the predominate contributor was from drilling results at the Khalda Concession which benefited from a full year of associated condensate related to increased Qasr field gas production.

U.S. crude oil revenues for 2006 increased $162 million, with a 13 percent increase in crude oil price realizations contributing $151 million of the additional revenues and a small increase in 2006 oil production contributing the remaining $11 million. The third-quarter 2005 hurricanes reduced Apache s 2006 average annual daily crude oil production 13,100 b/d, compared to 10,813 b/d in 2005. Shut-in production reduced the Company s 2006 and 2005 crude oil revenues by approximately $297 million and $186 million, respectively. Central region production rose 18 percent, reflecting drilling and recompletion activity in the Permian basin and southeast New Mexico, and the Amerada Hess acquired properties. Gulf Coast production was 10 percent below 2005 levels with downtime, hurricane production shut-ins and natural decline outpacing growth attributed to drilling and recompletion activity and the BP acquired properties.

Argentina s 2006 oil revenues increased $91 million over 2005 with $89 million of the increase associated with production growth, driven primarily by acquired properties and subsequent exploitation activities. Higher oil price realizations generated the other $2 million.

The North Sea s 2006 crude oil revenues were $80 million higher than 2005 with $240 million of additional revenues generated from a 19 percent increase in price realizations, partially offset by lower production, which was down 11 percent on a comparative basis. Production was lower in 2006 primarily because of production interruptions associated with commissioning of major infrastructure projects and temporary unplanned shutdown of the third-party Forties Pipeline System during the third quarter of 2006. The focus on upgrades in 2006 also displaced drilling operations necessary to mitigate natural decline.

Canada s 2006 oil revenues increased $17 million over 2005, with $56 million of additional revenues associated with higher price realizations, partially offset by lower production, which was down eight percent. Canadian production was down in most areas as natural decline exceeded drilling and production enhancement activities.

Australia s 2006 crude oil revenues were $27 million less than 2005, as a 23 percent decline in production more than offset an 18 percent increase in realized price. The production decrease resulted from normal field decline which offset a full year of associated condensate production from the John Brookes field and other development activities, mainly in the Bambra, Zephyrus and Stag areas.

China s 2006 oil revenues were $59 million less than 2005, a consequence of the August 2006 divestiture.

Natural Gas Revenues Our 2006 consolidated natural gas revenues increased $73 million from the prior year with $614 million of additional revenues generated from production growth mostly offset by the effect of a 19 percent decline in realized prices. All core gas producing regions generated additional revenues in 2006 from production growth; however they were mostly offset by lower relative natural gas prices.

Egypt contributed $73 million more to 2006 consolidated natural gas revenues on a 31 percent increase in production and a four percent decrease in realized gas prices. The year-over-year production growth came primarily from the Khalda concession, mostly attributable to a full year of production from the Qasr field.

Argentina s 2006 natural gas revenues increased $38 million, with all of the additional revenues associated with production growth. As with oil, the production growth primarily came from acquired properties and subsequent exploitation activities.

Australia s 2006 natural gas revenues were $35 million higher than 2005. Natural gas production increases added $38 million to revenues, while lower gas price realizations reduced revenues $3 million. The additional production was attributed to a full year of production from the John Brookes field.

U.S. natural gas revenues were $17 million higher in 2006. U.S. natural gas production, up 12 percent, contributed $166 million of additional revenues, while a nine percent price decline lowered revenues $149 million. The 2005 hurricanes reduced Apache s 2006 average annual daily natural gas production 37 MMcf/d compared to 59 MMcf/d in 2005. Shut-in production from the hurricanes reduced the Company s 2006 and 2005 natural gas revenues by approximately $95 million and $211 million, respectively. Central region production rose 16 percent from 2005, benefiting from drilling and recompletion activity, primarily in central and western Oklahoma, in East Texas and from acquired properties. Gulf Coast region production was nine percent above 2005 levels on the BP acquired properties, hurricane restoration, and drilling and recompletion activity, principally in the Chauvin, Ship Shoal and South Timbalier fields.

Canada s 2006 natural gas revenues decreased $91 million from 2005. An additional $72 million of revenues generated from a nine percent increase in production were more than offset by the impact of a 16 percent decrease in realized natural gas prices. Canada s production growth was concentrated in the North and South Grant Lands and Kabob areas, with activity in other areas more than offset by natural decline.

Costs

The table below compares our costs on an absolute dollar basis and an equivalent unit of production (boe) basis. Our discussion may reference either expenses on a boe basis or expenses on an absolute dollar basis, or both, depending on their relevance.

	Year Ended December 31,			Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
	(In millions)			(Per boe)		
Depreciation, depletion and amortization:						
Oil and gas property and equipment	$ 2,208	$ 1,699	$ 1,325	$ 10.78	$ 9.29	$ 7.99
Other assets	140	118	91	.68	.64	.55
Asset retirement obligation accretion	96	89	54	.47	.48	.32
Lease operating expenses	1,706	1,362	1,041	8.33	7.45	6.27
Gathering and transportation	118	104	100	.58	.57	.60
Severance and other taxes	542	554	453	2.65	3.03	2.73
General and administrative expenses	275	211	198	1.34	1.16	1.20
Financing costs, net	220	142	116	1.07	.78	.70
Total	$ 5,305	$ 4,279	$ 3,378	$ 25.90	$ 23.40	$ 20.36

Year 2007 Compared to Year 2006

Depreciation, Depletion and Amortization (DD&A) The following table details the changes in DD&A of oil and gas properties between 2007 and 2006.

	DD&A (In millions)
2006	$ 1,699
Volume change	210
Rate change	299
2007	$ 2,208

Full-cost DD&A expense totaled $2.2 billion, $509 million more than 2006. Production growth drove $210 million of the increase; the remainder is a consequence of higher costs. DD&A per boe averaged $10.78, $1.49 higher than 2006 as the costs to acquire, find and develop reserves continued to exceed our historical cost basis. Increasing costs also impact our estimates for future development of known reserves and estimates to abandon properties, both of which impact our full-cost depletion rate.

DD&A on other assets increased $22 million to $140 million with facilities coming online, in Canada, Egypt and the U.S. A full year of DD&A on assets acquired during 2006 in Argentina also contributed to the year-over-year increase.

Lease Operating Expenses (LOE) LOE is comprised of several components: direct operating costs, repair and maintenance, ad valorem taxes, and workover costs.

Direct operating costs are generally driven by commodity price levels, the type of commodity produced and the location of properties (i.e. offshore, onshore, remote locations, etc). Rising commodity prices impact operating cost elements directly and indirectly. They directly impact costs such as power, fuel, and chemicals which are commodity price based. Other items such as labor, boats, helicopters and materials and supplies are indirectly impacted as high prices increase activity and demand and thus, costs. Our operating costs increased 12 percent in 2007 and 19 percent in 2006 when compared to the prior year driven by increasing commodity prices. Our average realized commodity price per boe for 2007 was 10 percent higher than 2006, eight percent higher than 2005, and 50 percent higher than 2004. Oil is inherently more expensive to produce than natural gas. Oil and liquids were 47 percent of our production in both 2007 and 2006. A significant portion of our ad valorem taxes are reserve based and increase when prices rise. Repair and maintenance costs are higher on offshore properties and in areas with remote plants and facilities. All production in Australia and the North Sea and over 80 percent from the U.S. Gulf Coast region is from offshore properties. Workovers accelerate production; hence, they generally rise with commodity prices. In addition, workover activity generally increases after acquisitions. Fluctuations in exchange rates 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. In 2007, the U.S. dollar weakened 18, 11 and two percent relative to the Canadian dollar, the Australian dollar and the British Pound, respectively.

The following discussion will focus on per-unit costs which we believe to be the most meaningful measure for analyzing LOE.

LOE averaged $8.33 per boe, an increase of $.88. Almost two-thirds of the increase was from additional workover activity ($.16), a weakening U.S. dollar ($.16), hurricane repair activity ($.15), incentive-based compensation ($.07) and ad valorem taxes ($.03). The remaining increase is the result of the inflationary impact of higher commodity prices on all other operating costs, as described above.

The U.S. contributed $.45 to the $.88 per boe increase. Driving factors in the increase were additional hurricane repairs ($.15), more workover activity ($.13), acquired Permian basin oil properties which carry a higher rate than our historical average ($.05), incremental incentive-based compensation with Apache s rising stock price ($.04), higher ad valorem taxes ($.03), and the inflationary impact higher commodity prices have on operating costs ($.05). Over two-thirds of the increase in workover activity occurred on properties acquired in March 2007, in the Permian basin of West Texas.

Canada added $.34 per boe to the consolidated rate, $.09 of which was attributed to a decline in relative production. A weakening U.S. dollar negatively impacted the rate an additional $.09. The balance of the increase related to higher levels of workover activity ($.03), higher ad valorem taxes ($.02), lease rentals ($.02), company labor ($.02) and generally higher costs.

The North Sea increased the consolidated rate $.09 per boe; the net impact of a $.10 per boe increase on a decline in production volumes and a reduction of $.01 on lower costs. The benefit of decreases in diesel fuel consumption ($.08) and lower turnaround expenses more than offset increases from the impact of the weakening U.S. dollar ($.05), higher standby and supply boat costs ($.01) and higher contract labor ($.01). We are seeing the benefits of several years of facility upgrades to reduce the operating costs, including completion of our power generation ring.

Australia increased the consolidated rate $.09 per boe over 2006. The increase was primarily a result of our acquisition of an additional interest in Legendre, an oil field which carries a higher cost per barrel than our existing blended Australian rate ($.06), and appreciation of the Australian dollar relative to the U.S. dollar ($.02).

Two Argentine acquisitions, in April and September 2006, lowered the 2007 consolidated rate $.13 per boe. The LOE rate on these properties was lower than our existing consolidated rate.

Egypt had no impact on the consolidated rate. Our 2006 exit from China increased the 2007 consolidated rate $.04 per boe.

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 both the U.S. and Canada, we sell oil and natural gas under both types of arrangements. In the North Sea, we pay transportation 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. In Argentina, we sell oil and natural gas 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, 2007	2006
	(In millions)	
U.S.	$ 38	$ 32
Canada	35	34
North Sea	27	26
Egypt	15	11
Argentina	3	1
Total Gathering and Transportation	$ 118	$ 104
Total Gathering and Transportation per boe	$ .58	$ .57

These costs are primarily related to the portion of natural gas in our U.S. and Canadian operations sold under arrangements where we pay transportation directly to third parties, and North Sea crude oil sales and our Egyptian crude oil exports not sold under netback arrangements. The $14 million increase was driven primarily by U.S. production growth, an increase in Egyptian crude exports not sold under netback arrangements and a full year of transportation costs paid to third parties in Argentina.

Severance and Other Taxes Severance and other taxes are primarily comprised of severance taxes on properties onshore and in state or provincial waters in the U.S. and Australia, and the United Kingdom (U.K.) Petroleum Revenue Tax (PRT). 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 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, 2007	2006

	(In millions)	
Severance taxes.	$ 142	$ 122
U.K. PRT	346	394
Other taxes	54	38
Total Severance and Other Taxes	$ 542	$ 554
Total Severance and Other Taxes per boe	$ 2.65	$ 3.03

Severance and other taxes decreased $12 million, or two percent, on an absolute basis. On a per-unit basis they decreased $.38, or 13 percent, reflecting the 12 percent increase in equivalent production. The increase in severance taxes was driven by higher production and prices on U.S. and Australian properties burdened by such taxes. U.K. PRT was 12 percent below 2006, largely driven by lower comparable revenues on less production and slightly higher deductible costs. Deductible costs include capital expenditures, LOE, general and administrative expenses (G&A), and transportation tariffs. Other taxes increased with a full year of taxes on invoice and bank transactions in Argentina.

General and Administrative Expenses G&A was $64 million, or $.18 per boe, higher than 2006. Incentive-based compensation added $.12 per boe to the rate, a consequence of strong stock price appreciation during the year, while insurance costs added $.11 per boe, a consequence of industry-wide premium increases after the 2005 hurricanes. These increases were partially offset by a decrease in rate stemming from higher production.

Financing Costs, Net The major components of financing costs, net, include interest expense and capitalized interest. Net financing costs for 2007 increased $78 million or $.29 per boe, on higher average outstanding debt balances, which offset a slightly lower average interest rate.

Provision for Income Taxes The 2007 provision for income taxes was $1.9 billion, $403 million above 2006 on both higher taxable income and a higher effective tax rate. Apache s 2007 effective tax rate was 39.8 percent compared to 36.3 percent in 2006. 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 taxes. 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. The 2006 effective tax rate was impacted by a charge related to retroactive application of a 10 percent increase in the oil and gas company supplemental tax enacted by the U.K, a benefit from a Canadian federal and provincial tax rate reduction enacted in the second quarter of 2006 and a gain recognized on the sale of China. Foreign currency fluctuations had a negligible impact on the 2006 rate.

Year 2006 Compared to Year 2005

Depreciation, Depletion and Amortization The following table details changes in DD&A of oil and gas properties between 2006 and 2005:

	DD&A (In millions)
2005 DD&A	$ 1,325
Volume change	150
Rate change	224
2006 DD&A	$ 1,699

Our 2006 full-cost DD&A expense totaled $1.7 billion, $374 million more than 2005. Our 2006 full-cost DD&A rate of $9.29 per boe was $1.30 per boe more than 2005, reflecting rising acquisition costs, higher abandonment cost estimates, rising industry-wide drilling and finding costs, especially in the U.S. and Canada, and incremental future development costs associated with recent acquisitions and newly identified development projects. The increase in costs, including increased estimates of future development costs, is related to increased demand for drilling and associated services, a consequence of both higher oil and gas prices and additional demand resulting from the ongoing need to repair damage caused by hurricanes Katrina and Rita in 2005. The increase in 2006 DD&A, relative to 2005 was mitigated by a decline in Egypt resulting from the January 2006 sale of Egypt s deepwater acreage. Our 2006 full-cost DD&A expense was $73 million lower because of the production shut-in for hurricane damage.

Depreciation of other assets increased $27 million in 2006, reflecting ongoing development of infrastructure in Canada that began in 2005 to accommodate development on the acquired ExxonMobil acreage, and the Qasr field support facilities in Egypt, including completion of the Tarek gas plant inter-connect.

Lease Operating Expenses LOE averaged $7.45 per boe in 2006, $1.18 per boe higher than 2005. The 2005 hurricanes increased our worldwide rate by $.44 per boe in 2006, a reflection of shut-in production and additional expenses in excess of our insurance coverage. The remainder of the increase was driven by industry-wide cost increases, as discussed above, workover activity, a weaker U.S. dollar relative to the Canadian dollar and British Pound and higher non-hurricane related repair costs in our U.S. Gulf Coast and Canadian regions.

The U.S. added $.63 per boe to the 2006 worldwide rate. The Central region added $.04 per boe, with production growth nearly outpacing increases in costs, while the Gulf Coast region added $.59 per boe. In addition to the impact of industry-wide cost increases, activity levels soared in the Gulf of Mexico as producers continued to repair and restore production following the 2005 hurricanes. This increase in demand on top of an already tight-supply market for boats, helicopters, divers, labor, equipment and parts to complete repairs, pushed costs even higher in the region. The region s 2006 LOE included approximately $26 million, or $.14 per boe, for repairs in excess of insurance coverage. The 2006 rate increase was also impacted by additional workover activity, higher insurance rates and more non-hurricane repair costs, relative to 2005.

Canada added $.40 per boe to the 2006 worldwide rate. Higher costs added $.46 per boe, while production growth reduced the rate $.06. The weakening U.S. dollar accounted for $.09 per boe of the increase. The balance related to a higher level of workover activity, higher repair and maintenance costs, reclamation and restoration projects undertaken during 2006 and the general rise in costs, including increases in power rates, contract labor and fuel.

Egypt added $.02 to the 2006 worldwide rate as a $32 million increase in costs, including increased workover activity, was mostly offset by associated production growth.

Australia reduced the 2006 worldwide rate $.11 per boe with production growth more than offsetting associated incremental operating costs.

The North Sea added $.37 per boe to the 2006 consolidated rate, with approximately two-thirds of the increase in rate related to lower relative production, the strengthening British Pound and an increase in pension liabilities. The balance of the increase in costs related to major 2006 turnaround activity, higher fuel rates and usage as major projects were commissioned and higher maintenance and repair activity, relative to 2005.

Argentina reduced the 2006 consolidated rate $.19 per boe with production growth related to the 2006 acquisitions more than offsetting associated incremental operating costs.

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

	For the Year Ended December 31, 2006	2005
	(In millions)	
U.S.	$ 32	$ 30
Canada	34	33
North Sea	26	28
Egypt	11	8
Argentina	1	
Other International		1
Total Gathering and Transportation	$ 104	$ 100
Total Gathering and Transportation per boe	$ .57	$ .60

These costs are primarily related to the transportation of natural gas in our North American operations, North Sea crude oil sales and Egyptian crude oil exports. The four percent increase in costs for 2006 was driven primarily by U.S. production growth and Egyptian crude exports.

Severance and Other Taxes The table below presents a comparison of these expenses:

	For the Year Ended December 31, 2006	2005
	(In millions)	
Severance taxes.	$ 122	$ 139
U.K. PRT	394	285
Other	38	29
Total Severance and Other Taxes	$ 554	$ 453
Total Severance and Other Taxes per boe	$ 3.03	$ 2.73

Severance and other taxes totaled $554 million in 2006, $101 million greater than 2005. U.K. PRT increased $109 million in 2006 on a six percent increase in revenue and a 21 percent decrease in qualifying deductible capital spending. Australia s severance taxes declined on lower revenues associated with lower oil production. Canada s severance taxes decreased $6 million with the phase out of the federal large corporation tax. Other taxes increased $9 million on additional U.S. franchise taxes, consistent with our growth and a $5 million special profits charge levied on petroleum revenues by the Chinese government.

General and Administrative Expenses G&A averaged $1.16 per boe for 2006, $.04 per boe less than 2005. Absolute costs increased $13 million to $211 million. The additional cost in 2006 was primarily associated with expansion of international operations in conjunction with acquisitions and increasing insurance costs.

Financing Costs, Net Net financing costs for 2006 were $26 million higher than in 2005. Gross interest expense increased $42 million in 2006 as a result of a higher average debt balance and higher short-term interest rates. Capitalized interest increased $4 million, a result of a higher average unproved property balance. Interest income rose $10 million compared to 2005 on higher cash balances. Our weighted-average cost of borrowing on December 31, 2006 was 6.3 percent compared to 6.7 percent on December 31, 2005.

Provision for Income Taxes Income tax expense for 2006 totaled $1.5 billion, $125 million less than 2005. The effective tax rate for 2006 was 36.3 percent, down from 37.6 percent in 2005. The 2006 effective rate was impacted by a combination of federal and provincial tax rate reductions enacted by Canada during the second quarter of 2006, a 10 percent increase in the oil and gas company supplemental tax enacted by the U.K. during the third quarter of 2006 and the gain recognized on the sale of China, as discussed below. Currency fluctuations had a negligible impact on the 2006 effective tax rate.

The effective income tax rate for 2006 was impacted by the gain recognized in conjunction with divestment of operations in China. The Company intends to permanently reinvest earnings of its foreign subsidiaries and as such, has not recorded U.S. income tax expense on any undistributed foreign earnings, including the gain from the China sale.

Acquisitions and Divestitures

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. Apache must spend the entire $30 million in qualified expenditures during the initial term or pay the difference as liquidated damages.

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 the natural gas production.

Divestitures In 2007 we sold non-strategic oil and gas properties located in northwest Louisiana for approximately $56 million.

Subsequent Divestitures On January 29, 2008, the Company completed the sale of its 50 percent interest in Ship Shoal blocks 349 and 369 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 properties in the Permian basin of West Texas and New Mexico to Vanguard Permian, LLC for $78 million.

2006 Activity

U.S. Permian Basin On January 5, 2006, the Company purchased Amerada Hess s interest in eight fields located in the Permian basin of West Texas and New Mexico. The original purchase price was reduced from $404 million to $269 million because other interest owners exercised their preferential rights to purchase a number of the properties. The settlement price at closing of $239 million was adjusted for revenues and expenditures occurring between the effective date and the closing date of the acquisition. The acquired fields had estimated proved reserves of 27 MMbbls of liquid hydrocarbons and 27 Bcf of natural gas as of year-end 2005.

Argentina On April 25, 2006, the Company acquired the operations of Pioneer Natural Resources (Pioneer) in Argentina for $675 million. The settlement price at closing, of $703 million, was adjusted for revenues and expenditures occurring between the effective date and closing date of the acquisition. The properties are located in the Neuquén, San Jorge and Austral basins of Argentina and had estimated net proved reserves of approximately 22 MMbbls of liquid hydrocarbons and 297 Bcf of natural gas as of December 31, 2005. Eight gas processing plants (five operated and three non-operated), 112 miles of operated pipelines in the Neuquén basin and 2,200 square miles of three-dimensional (3-D) seismic data were also included in the transaction. Apache financed the purchase with cash on hand and commercial paper.

The purchase price was allocated to the assets acquired and liabilities assumed based upon the estimated fair values as of the date of acquisition, as follows (in thousands):

Proved property	$ 501,938
Unproved property	189,500
Gas Plants	51,200
Working capital acquired, net	11,256
Asset retirement obligation	(13,635)
Deferred income tax liability	(37,630)
Cash consideration	$ 702,629

On September 19, 2006, Apache acquired additional interests in (and now operates) seven concessions in the Tierra del Fuego Province from Pan American Fueguina S.R.L. (Pan American) for total consideration of $429 million. The settlement price at closing of $396 million was adjusted for normal closing items, including revenues and expenses between the effective date and the closing date of the acquisition. Apache financed the purchase with cash on hand

and commercial paper.

The total cash consideration allocated below includes working capital balances purchased, asset retirement obligations assumed and an obligation to deliver specific gas volumes in the future. The purchase price was allocated to the assets acquired and liabilities assumed based upon the estimated fair values as of the date of acquisition, as follows (in thousands):

Proved property	$ 289,916
Unproved property	132,000
Gas plants	12,722
Working capital acquired, net	8,929
Asset retirement obligation	(1,511)
Assumed obligation	(46,000)
Cash consideration	$ 396,056

U.S. Gulf Coast In June 2006, the Company acquired the remaining producing properties of BP plc (BP) on the Outer Continental Shelf of the Gulf of Mexico. The original purchase price was reduced from $1.3 billion for 18 producing fields to $845 million because other interest owners exercised their preferential rights to purchase five of the 18 fields. The purchase price consisted of $747 million of proved property, $42 million of unproved property and $56 million of facilities. The settlement price on the date of closing of $821 million was adjusted primarily for revenues and expenditures occurring between the April 1, 2006 effective date and the closing date of the acquisition. The acquired properties include 13 producing fields (nine of which are operated) with estimated proved reserves of 19.5 MMbbls of liquid hydrocarbons and 148 Bcf of natural gas. Apache financed the purchase with cash on hand and commercial paper.

Divestitures On January 6, 2006, the Company completed the sale of its 55 percent interest in the deepwater section of Egypt s West Mediterranean Concession to Amerada Hess for $413 million. Apache did not have any proved reserves booked for these properties.

On August 8, 2006, the Company completed the sale of its 24.5 percent interest in the Zhao Dong block, offshore the People s Republic of China, to Australia-based ROC Oil Company Limited for $260 million, marking Apache s exit from China. The effective date of the transaction was July 1, 2006. The Company recorded a gain of $174 million in the third quarter of 2006.

Capital Resources and Liquidity

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for each of the three years ended December 31. The table presents capital expenditures on a cash basis; therefore, the amounts differ from the amounts of capital expenditures, including accruals that are referred to elsewhere in this document.

	Year Ended December 31,		
	2007	2006 (In millions)	2005
Sources of Cash and Cash Equivalents:			
Net Cash Provided by Operating Activities	$ 5,677	$ 4,313	$ 4,332
Sales of property and equipment	67	678	80
Net commercial paper and money market borrowings		1,630	
Debt borrowings	2,002		
Common stock issuances	44	39	26
Other	26	36	6
	7,816	6,696	4,444
Uses of Cash and Cash Equivalents:			
Capital expenditures	4,802	4,140	3,716
Acquisitions	1,005	2,164	
Net commercial paper and money market repayments	1,425		396
Payments on debt	170		
Repurchase of common stock		174	
Dividends	205	154	117
Other	224	152	97
	7,831	6,784	4,326
Increase (decrease) in cash and cash equivalents	$ (15)	$ (88)	$ 118

Net Cash Provided by Operating Activities Net cash provided by operating activities (operating cash flow) is our primary source of capital and liquidity. Factors affecting changes in operating cash flow are largely the same as those that affect net earnings, with the exception of noncash expenses such as DD&A and deferred income tax expense. As a result, our 2007 operating cash flow increased from 2006, largely from increases in net earnings, as discussed in the Results of Operations section of this report. Operating cash flow in 2006 was flat to 2005.

Debt On January 26, 2007, the Company issued $500 million principal amount, $499.5 million net of discount, of senior unsecured 5.625% notes maturing January 15, 2017 and $1 billion principal amount, $993 million net of discount, of senior unsecured 6% notes maturing January 15, 2037. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay a portion of the Company s commercial paper outstanding at the end of 2006 in anticipation of funding our $1 billion acquisition of Permian basin properties from Anadarko which closed March 29, 2007, and for general corporate purposes.

On April 16, 2007, the Company issued $500 million principal amount, $498.8 million net of discount, of senior unsecured 5.25% notes maturing April 15, 2013. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay a portion of the Company s outstanding commercial paper and for general corporate purposes.

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

	Year Ended December 31, 2007	2006	2005
		(In thousands)	
Exploration and Development:			
United States	$ 1,630,776	$ 1,532,959	$ 1,072,040
Canada	650,676	1,056,614	1,188,096
Egypt	605,115	454,892	352,324
Australia	516,054	179,892	217,816
North Sea	537,868	329,498	489,072
Argentina	287,047	115,570	25,963
China		12,288	22,521
	4,227,536	3,681,713	3,367,832
Acquisitions Oil and gas properties	1,024,956	2,428,432	39,228
Asset Retirement Costs	439,368	390,612	546,669
Capitalized Interest	75,748	61,301	56,988
Gathering, Transmission and Processing Facilities	473,481	248,589	392,872
Total capital expenditures	$ 6,241,089	$ 6,810,647	$ 4,403,589

Exploration and Development (E&D) Increases in our 2007 cash flows enabled us to invest larger amounts on E&D capital projects during the year. We invested $4.2 billion on exploration and development activities in 2007, up 15 percent from 2006. Our 2006 E&D capital expenditures were $314 million above 2005.

In the U.S., we invested $1.6 billion on exploration and development activities in 2007. Our Gulf Coast region invested approximately $1 billion on drilling, recompletions, and platform and production support facilities, including $46 million of associated hurricane redevelopment capital in excess of insurance coverage. The region drilled 54 wells in the Gulf of Mexico and 30 wells onshore, with a 77 percent success rate, despite ongoing hurricane repair activity. The Central region had its most active year ever investing $637 million, including the drilling of 343 wells with a 98 percent success rate. The region added to its inventory of opportunities to grow production with the addition of Permian basin properties from Anadarko in the first quarter of 2007.

Canada s drilling program accounted for more than 31 percent of the Company s wells drilled. The region invested $651 million in 2007 on exploration and development activities and drilled 348 wells with an 83 percent success rate.

We invested $538 million in the North Sea on exploration and development drilling, recompletions and facility upgrades. Five of 16 exploration and development wells drilled during 2007 were productive.

Egypt had another active and successful exploration and development program investing $605 million, drilling 192 wells at an 84 percent success rate.

In Australia, we invested $516 million in exploration and development activities as we participated in drilling 28 wells, 14 exploration wells and 14 development wells. Three of the exploration wells and six of the development wells were productive for a success rate of 32 percent.

In Argentina our 2007 exploration and development activities increased by $171 million over 2006 as we invested $287 million drilling 94 wells, three exploratory and 91 development, with a 98 percent success rate.

Acquisitions We completed $1 billion of acquisitions in 2007 compared to $2.4 billion in 2006. Acquisition capital expenditures occur as attractive opportunities arise and therefore, vary from year to year.

Asset Retirement Costs In 2007, we also recorded $439 million of additional asset retirement costs. The increase is primarily related to revisions of our cost estimates. The continued escalation of service costs and the high level of abandonment activities in the Gulf Coast region have increased our expected obligations. Continued worldwide drilling programs and acquisition activity also contributed to the increased abandonment costs.

Gathering, Transmission and Processing Facilities (GTP) We invested $473 million in GTP facilities in 2007 compared to $249 million in 2006. In Egypt we invested $422 million on the expansion of gas processing facilities to alleviate the processing capacity bottleneck throttling deliverability. In Canada, we invested $24 million in processing plants.

2008 Outlook We plan another active year of drilling. Because we revise our estimates of exploration and development capital expenditures frequently throughout the year based on industry conditions, year-to-year results and the relative levels of commodity prices and service costs, accurately projecting future expenditures is difficult at best. At the end of 2007, we had a fairly active drilling program underway; however, if commodity prices soften and service costs do not decline accordingly, Apache will not hesitate to reduce activity until margins are back in line. Conversely, should commodity prices increase we may increase 2008 expenditures accordingly. Our 2008 preliminary plan includes exploration and development capital of approximately $4.6 billion and GTP of approximately $400 million. We generally do not project estimates for acquisitions because their timing is unpredictable. We continually look for properties in which we believe we can add value and earn adequate rates of return and will take advantage of those opportunities as they arise.

Debt Repayment The $170 million Apache Finance Pty Ltd (Apache Finance Australia) 6.5% notes matured on December 17, 2007. The notes were repaid using funds borrowed on Apache s commercial paper program.

Repurchases of Common Stock On April 19, 2006, the Company announced that its board of directors authorized the purchase of up to 15 million shares of the Company s common stock representing a market value of approximately $1 billion on the date of announcement. The Company may buy shares from time to time on the open market, in privately negotiated transactions, or a combination of both. The timing and amounts of any purchases will be at the discretion of Apache s management. The Company initiated the purchase program on May 1, 2006, after the Company s first-quarter 2006 earnings information was disseminated in the market. During 2006, the Company purchased 2,500,000 shares at an average price of $69.74 per share. No stock purchases were made in 2007.

Dividends The Company has paid cash dividends on its common stock for 43 consecutive years through 2007. Future dividend payments will depend on the Company s level of earnings, financial requirements and other relevant factors. Common dividends paid during 2007 rose 34 percent to $199 million, reflecting the increase in common shares outstanding and the higher common stock dividend rate. The Company increased its quarterly cash dividend 50 percent, to 15 cents per share from 10 cents per share, effective with the November 2006 dividend payment. Common dividends paid during 2006 rose 33 percent to $148 million, reflecting the increase in common shares outstanding and the higher common stock dividend rate.

During 2007 and 2006, Apache paid a total of $6 million in dividends each year on its Series B Preferred Stock issued in August 1998. See Note 7 Capital Stock of Item 15 in this Form 10-K.

Liquidity

	At December 31,		
	2007	**2006**	**2005**
Millions of dollars except as indicated			
Net cash provided by operating activities	$ 5,677	$ 4,313	$ 4,332

Total debt	4,227	3,822	2,192
Shareholders equity	15,378	13,191	10,541
Percent of total debt to capitalization	22%	22%	17%
Floating-rate debt/total debt	5%	43%	

In recent years, our primary sources of capital and liquidity has been operating cash flow. Additionally, we maintain revolving credit facilities and a commercial paper program which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. During 2006, another source of liquidity was the divestiture of our assets in China. We expect the combination of these sources of capital will be more than adequate to fund costs and expenses necessary to maintain continued operations, future capital expenditures, payment of principal and interest on outstanding debt, dividends and other contractual obligations as discussed later in this section.

Operating Cash Flow Historically, fluctuations in commodity prices have been the primary reason for the Company s short-term changes in cash provided by operating activities. Sales volume changes have also impacted operating cash flow in the short-term, but have not been as volatile as commodity prices. Apache s long-term operating cash flow from operating activities is dependent on commodity prices, reserve replacement and the level of costs and expenses required for continued operations.

Our business, as with other extractive industries, is a depleting one in which each barrel produced must be replaced or the Company, and a critical source of our future liquidity, will shrink. Cash investments are continuously required to fund exploration and development projects and acquisitions which are necessary to offset the inherent declines in production and proven reserves. See Item 1 and 2, Business and Properties, Risks Factors, in this Form 10-K. Future success in maintaining and growing reserves and production will be highly dependent upon having adequate capital resources available, success in both exploration and development activities and acquiring additional reserves.

Our 2007 year-end reserve life index indicates an average decline of 8.4 percent per year. This projection is based on production and prices at year-end 2007, except in those instances where future natural gas and oil sales are covered by physical contract terms providing for higher or lower prices, estimates of investments required to develop estimated proved undeveloped reserves, and costs and taxes reflected in our standardized measure in Note 12 - Supplemental Oil and Gas Disclosures (Unaudited) of Item 15 in this Form 10-K.

Debt and Credit Facilities Year-end 2007 outstanding current and long-term debt totaled $4.2 billion, $405 million higher than year-end 2006. The Company s outstanding debt consists of notes, debentures, commercial paper and uncommitted bank lines maturing intermittently in years 2008 through 2096. Debt due in 2008 includes $135 million of commercial paper, $80 million of money market lines of credit and a small note. Apache s commercial paper is fully supported by available borrowing capacity under committed credit facilities which expire in 2012. In 2009, $100 million in debt matures with the remaining $3.9 billion maturing thereafter.

On April 30, 2007, the Company amended its existing $1.5 billion U.S. five-year revolving credit facility to extend the maturity date one year to May 28, 2012. The amendment also allows the Company to increase the size of the facility by up to $750 million by adding commitments from new or existing lenders.

The Company also amended its $450 million U.S. credit facility, $150 million Australian credit facility and $150 million Canadian credit facility to extend the maturity dates of all the commitments to May 12, 2012. The amendment also allows the Company to increase the size of the U.S. facility by up to $250 million, the Australian facility by up to $150 million and the Canadian facility by up to $150 million by adding commitments from new or existing lenders.

As detailed above, the Company currently has $2.25 billion of syndicated bank credit facilities. The available borrowing capacity under the credit facilities at December 31, 2007, after netting outstanding commercial paper, was $2.1 billion. 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., Canada and Australia of up to five percent of the Company s consolidated assets, which approximated $1.4 billion as of December 31, 2007. There are no restrictions on incurring liens in countries other than the U.S., Canada and Australia. 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., Canadian and Australian subsidiaries, defaults on any direct payment obligation in excess of $100 million or has any unpaid, non-appealable judgment against it in excess of $100 million. The Company was in compliance with the terms of the credit facilities as of December 31, 2007.

Credit Ratings Apache s senior unsecured long-term debt is currently rated A3 by Moody s, A- by Standard & Poor s and A by Fitch. Apache s short-term debt rating for its commercial paper program is currently P-2 by Moody s, A-2 by Standard & Poor s and F1 by Fitch. The outlook is stable from all three rating agencies.

Oil and Gas Capital Expenditures We fund exploration and development activities primarily through net cash provided by operating activities and budget capital expenditures based on projected operating cash flow. Our operating cash flow, both in the short and long-term, is 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. Longer-term operating cash flow and capital spending projections are rarely used by management to operate the business. 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.

We use a combination of our operating cash flow, 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.

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, 2007. See Note 9 Commitments and Contingencies of Item 15 in this Form 10-K for further information regarding these obligations.

Contractual Obligations	Note Reference	Total	2008	2009-2011	2012-2013	2014 & Beyond
			(In thousands)			
Debt	Note 5	$ 4,226,679	$ 215,074	$ 99,890	$ 398,552	$ 3,513,163
Interest Payments	Note 5	5,017,435	251,385	736,655	438,145	3,591,250
Drilling rig commitments	Note 9	922,822	567,005	355,817		
Purchase obligations	Note 9	615,589	571,889	43,700		
E&D commitments	Note 9	308,962	150,356	158,606		
Firm transportation agreements	Note 9	119,677	33,808	38,796	11,489	35,584
Office and related equipment	Note 9	116,727	21,179	57,037	29,797	8,714
Oil and gas operations equipment	Note 9	528,475	82,772	156,728	56,252	232,723
Other		8,242	8,242			

Total Contractual Obligations(a)(b)(c)(d)	$ 11,864,608	$ 1,901,710	$ 1,647,229	$ 934,235	$ 7,381,434

(a) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1.9 billion. See Note 4 Asset Retirement Obligation of Item 15 in this Form 10-K for further discussion.

(b) This table does not include the company s $640 million liability for outstanding derivative instruments valued as of December 31, 2007. See Note 3 Hedging and Derivative Instruments of Item 15 in this Form 10-K for further discussion.

(c) This table does not include the Company s pension or postretirement benefit obligations. See Note 9 Commitments and Contingencies of Item 15 in this Form 10-K for further discussion.

(d) This table does not include the Company s FIN 48 obligations. See Note 6 Income Taxes of Item 15 in this Form 10-K for further discussion.

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 any impact on future liquidity. Such obligations include environmental contingencies and potential settlements resulting from litigation. Apache s management feels that it has adequately reserved for its contingent obligations including approximately $28 million for environmental remediation and approximately $7 million for various legal liabilities. See Note 9 Commitments and Contingencies of Item 15 in this Form 10-K for a detailed discussion of the Company s environmental and legal contingencies.

The Company also accrued approximately $41 million as of December 31, 2007, for an insurance contingency because of our involvement with Oil Insurance Limited (OIL). Apache is a member of this insurance pool which insures specific property, pollution liability and other catastrophic risks of the Company. As part of its membership, the Company is contractually committed to pay termination fees were we to elect to withdraw from OIL. Apache does not anticipate withdrawal from the insurance pool; however, the potential termination fee is calculated annually based on past losses and the liability reflecting this potential charge has been accrued as required.

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 requires 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:

Full-Cost Method of Accounting for Oil and Gas Operations The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful-efforts method and the full-cost method. There are several significant differences between these methods. Under the successful-efforts method, costs such as G&G, exploratory dry holes and delay rentals are expensed as incurred, where under the full-cost method these types of charges would be capitalized to their respective full-cost pool. In the measurement of impairment of oil and gas properties, the successful-efforts method of accounting follows the guidance provided in Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, where the first measurement for impairment is to compare the net book value of the related asset to its undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method, the net book value (full-cost pool) is compared to the future net cash flows discounted at 10 percent using commodity prices in effect on the last day of the reporting period (ceiling limitation). If the full-cost pool is in excess of the ceiling limitation, the excess amount is charged through income.

We have elected to use the full-cost method to account for our investment in oil and gas properties. Under this method, the Company capitalizes all acquisition, exploration and development costs for the purpose of finding oil and gas reserves, including salaries, benefits and other internal costs directly attributable to these finding activities. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. In addition, gains or losses on the sale or other disposition of oil and gas properties are not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country. As a result, we believe that the full-cost method of accounting better reflects the true economics of exploring for and developing oil and gas reserves. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas investments. Generally, the application of the full-cost method of accounting for oil and gas property results in higher capitalized costs and higher DD&A rates compared to similar companies applying the successful efforts methods of accounting.

Reserve Estimates Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. As such, our reserve engineers review and revise the Company s reserve estimates at least annually.

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.

Costs Excluded Under the full-cost method of accounting, oil and gas properties include costs that are excluded from capitalized costs being amortized (amortization base). These amounts represent investments in unproved properties and major development projects. Apache excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly by the Company s accounting, exploration and engineering staffs to determine if impairment has occurred. Nonproducing leases are evaluated based on the progress of the Company s exploration program to date. Exploration costs are transferred to the amortization base upon completion of drilling individual wells. If geological and geophysical (G&G) costs cannot be associated with specific properties, they are included in the amortization base as incurred. The amount of any impairment is transferred to the amortization base or a charge is made against earnings for those international operations where a proved reserve base has not yet been established. Impairments transferred to the amortization base increase the DD&A rate for that country. For international operations where a reserve base has not yet been established, all costs associated with a prospect or play would be considered quarterly for impairment upon full evaluation of such prospect or play. This evaluation considers among other factors, seismic data, requirements to relinquish acreage, drilling results, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions.

Impairments We assess all of our unproved properties for possible impairment on a quarterly basis based on geological trend analysis, dry holes or relinquishment of acreage. When impairment occurs, costs associated with these properties are generally transferred to our proved property base where they become subject to amortization.

Impairments in international areas without proved reserves are charged to earnings upon determination that impairment has occurred.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. Many of our receivables are from joint interest owners on properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Our crude oil and natural gas receivables are typically collected within two months. We accrue 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.

Beginning in 2001, we experienced a gradual decline in the timeliness of receipts from EGPC for our Egyptian oil and gas sales. During 2007, we experienced wide variability in the timing of cash receipts. We have not established a reserve for these Egyptian receivables because we continue to get paid, albeit late, and have no indication that we will not be able to collect our receivable.

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 regulations 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 are 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. We consider future taxable income in making such assessments. 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 have been fully documented in the Company s tax returns. 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.

Derivatives Apache uses derivative contracts to manage its exposure to oil and gas price volatility and foreign currency volatility. The Company accounts for the contracts in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. The estimated fair values of Apache s derivative contracts within the scope of this statement are carried on the Company s consolidated balance sheet. For oil and gas derivative contracts designated and qualifying as cash flow hedges, realized gains and losses are recognized in oil and gas production revenues when the forecasted transaction occurs. For foreign currency forward contracts designated and qualifying as cash flow hedges, realized gains and losses are generally recognized in lease operating expense when the forecasted transaction occurs. SFAS No. 133 requires that gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting be marked-to-market and reported in current period income, rather than in the period in which the hedged transaction is settled. Realized gains and losses on derivative contracts not qualifying as cash flow hedges are reported in Other under Revenues and Other of the Statement of Consolidated Operations.

The fair value estimate of Apache s derivative contracts requires judgment; however, the Company s derivative contracts are either exchange traded or valued by reference to commodities and currencies that are traded in highly liquid markets. As such, the ultimate fair value is determined by references to readily available public data. Option valuations are verified against independent third-party quotations. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk, Commodity Risk in this Form 10-K for commodity price sensitivity information and the Company s policies related to the use of derivatives.

Stock-Based Compensation Stock compensation awards granted are valued on the date of grant and are expensed, net of estimated forfeitures, on a straight-line basis over the required service period. Inherent in expensing stock options and other stock-based compensation are several judgments and estimates that must be made. These include determining the underlying valuation methodology for stock compensation awards and the related inputs utilized in each valuation, such as the Company s expected stock price volatility, expected term of the employee option, expected dividend yield, the expected risk-free interest rate, the underlying stock price and the exercise price of the option. Changes to these assumptions could result in different valuations for individual share awards and will be carefully scrutinized for each material grant. For option valuations, Apache utilizes the Black-Scholes option pricing model. For valuing the Share Appreciation Plan awards, the Company utilizes a Monte Carlo simulation model developed by a third party. Please refer to Note 7 Capital Stock of Item 15 of this Form 10-K for a detailed description of our stock compensation plans.

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, weather and climate, and governmental risks. 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

We periodically enter into hedging activities on a portion of our projected oil and natural gas production through a variety of financial and physical arrangements intended to support oil and natural gas prices at targeted levels and to manage our overall exposure to oil and gas price fluctuations. 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 generally hold or issue derivative instruments for trading purposes.

Apache historically only hedged long-term oil and gas prices related to a portion of its expected production associated with acquisitions; however, in 2006 and 2007, the Company s Board of Directors authorized management to hedge a portion of production generated from the Company s drilling program. Approximately 17 percent of 2007 natural gas and crude oil production was subject to financial derivative hedges.

On December 31, 2007, the Company had open natural gas derivative hedges in an asset position with a fair value of $59 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $59 million, while a 10 percent decrease in prices would increase the fair value by approximately $68 million. The Company also had open oil derivatives in a liability position with a fair value of $699 million. A 10 percent increase in oil prices would increase the liability by approximately $402 million, while a 10 percent decrease in prices would decrease the liability by approximately $368 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2007. See Note 3 Hedging and Derivative Instruments of Item 15 in this Form 10-K for notional volumes and terms associated with the Company s derivative contracts.

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 Chief 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, 2007, the Company s debt with fixed interest rates represented approximately 95 percent of total debt. As a result, the interest expense on approximately 5 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 $1.8 million.

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 the majority of the gas production is sold under fixed-price Australian dollar contracts. Over 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 U.K. 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. dollars equivalents based on the average exchange rates during the period.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of Other under Revenues and Other, or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company s provision for income tax expense on the Statement of Consolidated Operations.

Weather and Climate Risk

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impacts 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. While our planning for normal climatic variation, insurance program, and emergency recovery plans mitigate the effects of the weather, not all such effects can be predicted, eliminated or insured against.

Governmental Risk

Apache s U.S. and international operations have been, and at times in the future may be, affected by political developments and by federal, state, local and provincial laws and regulations impacting production levels, taxes, environmental requirements and other assessments including a potential Windfall Profits Tax. See Item 1A Risk Factors, for further discussion.

Forward-Looking Statements and Risk

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company s control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, capital expenditure projections, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Although Apache makes use of futures contracts, swaps, options and fixed-price physical contracts to mitigate risk, fluctuations in oil and gas prices, or a prolonged continuation of low prices may substantially adversely affect the Company s financial position, results of operations and cash flows.

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-57 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, 2007, 2006 and 2005, included in this report, have been audited by Ernst & Young LLP, independent public auditors, as stated in their audit report appearing herein.

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

Disclosure Controls and Procedures

G. Steven Farris, the Company s President, Chief Executive Officer and Chief Operating Officer, and Roger B. Plank, the Company s Executive Vice President and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2007, 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 were effective, providing effective means to insure that information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported in a timely manner. We also made no changes in internal controls over financial reporting during the quarter ending December 31, 2007 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 Item 15 of this report.

The independent auditors attestation report called for by Item 308(b) of Regulation S-K is incorporated by reference to Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting, included on Page F-3 in Item 15 of this report.

Changes in Internal Control Over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2007, 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 2008 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 Investor Relations page of the Company s website at http://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. 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 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***

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

ITEM 14. ***PRINCIPAL ACCOUNTANT FEES AND SERVICES***

The information set forth under the caption Independent Registered Public Accountants 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

Report of management	F-1
Report of independent registered public accounting firm	F-2
Report of independent registered public accounting firm	F-3
Statement of consolidated operations for each of the three years in the period ended December 31, 2007	F-4
Statement of consolidated cash flows for each of the three years in the period ended December 31, 2007	F-5
Consolidated balance sheet as of December 31, 2007 and 2006	F-6
Statement of consolidated shareholders equity for each of the three years in the period ended December 31, 2007	F-7
Notes to consolidated financial statements	F-8

2. Financial Statement Schedules

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

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger among Registrant, YPY Acquisitions, Inc. and The Phoenix Resource Companies, Inc., dated March 27, 1996 (incorporated by reference to Exhibit 2.1 to Registrant s Registration Statement on Form S-4, Registration No. 333-02305, filed April 5, 1996).
2.2	Purchase and Sale Agreement by and between BP Exploration & Production Inc., as seller, and Registrant, as buyer, dated January 11, 2003 (incorporated by reference to Exhibit 2.1 to Registrant s Current Report on Form 8-K, dated and filed January 13, 2003, SEC File No. 001-4300).
2.3	Sale and Purchase Agreement by and between BP Exploration Operating Company Limited, as seller, and Apache North Sea Limited, as buyer, dated January 11, 2003 (incorporated by reference to Exhibit 2.2 to Registrant s Current Report on Form 8-K, dated and filed January 13, 2003, SEC File No. 001-4300).
3.1	Restated Certificate of Incorporation of Registrant, dated February 11, 2004, as filed with the Secretary of State of Delaware on February 12, 2004 (incorporated by reference to Exhibit 3.1 to Registrant s Annual Report on Form 10-K for year ended December 31, 2003, SEC File No. 001-4300).
3.2	Bylaws of Registrant, as amended December 14, 2006 (incorporated by reference to Exhibit 3.2 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).
4.1	Form of Certificate for Registrant s Common Stock (incorporated by reference to Exhibit 4.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, SEC File

No. 001-4300).

4.2 Form of Certificate for Registrant s 5.68% Cumulative Preferred Stock, Series B (incorporated by reference to Exhibit 4.2 to Amendment No. 2 on Form 8-K/A to Registrant s Current Report on Form 8-K, dated and filed April 18, 1998, SEC File No. 001-4300).

4.3 Rights Agreement, dated January 31, 1996, between Registrant and 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).

Exhibit No.	Description
4.4	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. (successor 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).
4.5	Senior Indenture, dated February 15, 1996, between Registrant and JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank, as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.6 to Registrant s Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.6	First Supplemental Indenture to the Senior Indenture, dated as of November 5, 1996, between Registrant and 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).
4.7	Form of Indenture among Apache Finance Pty Ltd, Registrant and 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).
4.8	Form of Indenture among Registrant, Apache Finance Canada Corporation and 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.
10.3	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).
10.4	Form of Credit Agreement, dated as of May 12, 2005, among Apache Canada Ltd, a wholly-owned subsidiary of Registrant, the Lenders named therein, JPMorgan Chase Bank, N.A., as Global Administrative Agent, RBC Capital Markets and BMO Nesbitt Burns, as Co-Lead Arrangers and Joint Bookrunners, Royal Bank of Canada, as Canadian Administrative Agent, Bank of Montreal and Union Bank of California, N.A., Canada Branch, as Canadian Co-Syndication Agents, and The Toronto-Dominion Bank and BNP Paribas (Canada), as Canadian Co-Documentation Agents (excluding exhibits and schedules) (incorporated by reference to Exhibit 10.02 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, SEC File No. 001-4300).
10.5	

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).

Exhibit No.	Description
*10.6	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.
10.7	Concession Agreement for Petroleum Exploration and Exploitation in the Khalda Area in Western Desert of Egypt by and among Arab Republic of Egypt, the Egyptian General Petroleum Corporation and Phoenix Resources Company of Egypt, dated April 6, 1981 (incorporated by reference to Exhibit 19(g) to Phoenix s Annual Report on Form 10-K for year ended December 31, 1984, SEC File No. 1-547).
10.8	Amendment, dated July 10, 1989, to Concession Agreement for Petroleum Exploration and Exploitation in the Khalda Area in Western Desert of Egypt by and among Arab Republic of Egypt, the Egyptian General Petroleum Corporation and Phoenix Resources Company of Egypt (incorporated by reference to Exhibit 10(d)(4) to Phoenix s Quarterly Report on Form 10-Q for quarter ended June 30, 1989, SEC File No. 1-547).
10.9	Farmout Agreement, dated September 13, 1985 and relating to the Khalda Area Concession, by and between Phoenix Resources Company of Egypt and Conoco Khalda Inc. (incorporated by reference to Exhibit 10.1 to Phoenix s Registration Statement on Form S-1, Registration No. 33-1069, filed October 23, 1985).
10.10	Amendment, dated March 30, 1989, to Farmout Agreement relating to the Khalda Area Concession, by and between Phoenix Resources Company of Egypt and Conoco Khalda Inc. (incorporated by reference to Exhibit 10(d)(5) to Phoenix s Quarterly Report on Form 10-Q for quarter ended June 30, 1989, SEC File No. 1-547).
10.11	Amendment, dated May 21, 1995, to Concession Agreement for Petroleum Exploration and Exploitation in the Khalda Area in Western Desert of Egypt between Arab Republic of Egypt, the Egyptian General Petroleum Corporation, Repsol Exploration Egypt S.A., Phoenix Resources Company of Egypt and Samsung Corporation (incorporated by reference to Exhibit 10.12 to Registrant s Annual Report on Form 10-K for year ended December 31, 1997, SEC File No. 001-4300).
10.12	Concession Agreement for Petroleum Exploration and Exploitation in the Qarun Area in Western Desert of Egypt, between Arab Republic of Egypt, the Egyptian General Petroleum Corporation, Phoenix Resources Company of Qarun and Apache Oil Egypt, Inc., dated May 17, 1993 (incorporated by reference to Exhibit 10(b) to Phoenix s Annual Report on Form 10-K for year ended December 31, 1993, SEC File No. 1-547).
10.13	Agreement for Amending the Gas Pricing Provisions under the Concession Agreement for Petroleum Exploration and Exploitation in the Qarun Area, effective June 16, 1994 (incorporated by reference to Exhibit 10.18 to Registrant s Annual Report on Form 10-K for year ended December 31, 1996, SEC File No. 001-4300).
10.14	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).
10.15	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).
10.16	Apache Corporation 401(k) Savings Plan, dated January 1, 2007 (incorporated by reference to Exhibit 10.16 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).

10.17	Apache Corporation Money Purchase Retirement Plan, dated January 1, 2007 (incorporated by reference to Exhibit 10.17 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).
10.18	Non-Qualified Retirement/Savings Plan of Apache Corporation, amended and restated as of January 1, 2005 (incorporated by reference to Exhibit 10.18 to Registrant s Annual Report on Form 10-K for year ended December 31, 2006, SEC File No. 001-4300).
10.19	Apache Corporation 2007 Omnibus Equity Compensation Plan, dated February 8, 2007 (incorporated by reference to Appendix B to the Proxy Statement relating to Registrant s 2007 annual meeting of stockholders, as filed with the Commission on March 30, 2007, SEC File No. 001-4300).

Exhibit No.	Description
10.20	Apache Corporation 1995 Stock Option Plan, as amended and restated September 15, 2005, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.21	Apache Corporation 2000 Share Appreciation Plan, as amended and restated September 15, 2005, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.4 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.22	Apache Corporation 1996 Performance Stock Option Plan, as amended and restated September 13, 2001 (incorporated by reference to Exhibit 10.03 to Registrant s Quarterly Report on Form 10-Q, as amended by Form 10-Q/A, for the quarter ended September 30, 2001, SEC File No. 001-4300).
10.23	Apache Corporation 1998 Stock Option Plan, as amended and restated September 15, 2005, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.24	Apache Corporation 2000 Stock Option Plan, as amended and restated September 15, 2005, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.25	Apache Corporation 2003 Stock Appreciation Rights Plan, as amended and restated May 2, 2007, effective May 2, 2007 (incorporated by reference to Exhibit 10.2 to Registrant s Quarterly Report on Form 10-Q for quarter ended June 30, 2007, SEC File No. 001-4300).
10.26	Apache Corporation 2005 Stock Option Plan, as amended and restated May 2, 2007 (incorporated by reference to Exhibit 10.3 to Registrant s Quarterly Report on Form 10-Q for quarter ended June 30, 2007, Commission File No. 001-4300).
10.27	Apache Corporation 2005 Share Appreciation Plan, dated February 3, 2005 (incorporated by reference to Appendix C to the Proxy Statement relating to Apache s 2005 annual meeting of stockholders, as filed with the Commission on March 28, 2005, Commission File No. 001-4300).
10.28	1990 Employee Stock Option Plan of The Phoenix Resource Companies, Inc., as amended through September 29, 1995, effective April 9, 1990 (incorporated by reference to Exhibit 10.33 to Registrant s Annual Report on Form 10-K for year ended December 31, 1996, SEC File No. 001-4300).
10.29	Apache Corporation Income Continuance Plan, as amended and restated May 3, 2001 (incorporated by reference to Exhibit 10.30 to Registrant s Annual Report on Form 10-K for the year ended December 31, 2001, SEC File No. 001-4300).
10.30	Apache Corporation Deferred Delivery Plan, as amended and restated September 15, 2005, effective as of January 1, 2005 (incorporated by reference to Exhibit 10.5 to Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, SEC File No. 001-4300).
10.31	Apache Corporation Executive Restricted Stock Plan, as amended and restated May 2, 2007, effective May 2, 2007 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for quarter ended June 30, 2007, SEC File No. 001-4300).
10.32	Apache Corporation Non-Employee Directors Compensation Plan, as amended and restated February 8, 2007, effective as of January 1, 2007 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, SEC File No. 001-4300).
10.33	Apache Corporation Outside Directors Retirement Plan, as amended and restated May 4, 2006, effective as of January 1, 2006 (incorporated by reference to Exhibit 10.1 to Registrant s Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, SEC File No. 001-4300).
10.34	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).
10.35	Amended and Restated Employment Agreement, dated December 5, 1990, between Registrant and Raymond Plank (incorporated by reference to Exhibit 10.39 to Registrant s Annual Report on Form 10-K for year ended December 31, 1996, SEC File No. 001-4300).
10.36	First Amendment, dated April 4, 1996, to Restated Employment Agreement between Registrant and Raymond Plank (incorporated by reference to Exhibit 10.40 to Registrant s Annual Report on Form 10-K for year ended December 31, 1996, SEC File No. 001-4300).

Exhibit No.	Description
10.37	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).
10.38	Employment Agreement, dated June 6, 1988, between Registrant and G. Steven Farris (incorporated by reference to Exhibit 10.6 to Registrant s Annual Report on Form 10-K for year ended December 31, 1989, SEC File No. 001-4300).
10.39	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).
10.40	Amended and Restated Gas Purchase Agreement, effective July 1, 1998, by and among Registrant and MW Petroleum Corporation, as seller, and Producers Energy Marketing, LLC, as buyer (incorporated by reference to Exhibit 10.1 to Registrant s Current Report on Form 8-K, dated June 18, 1998, filed June 23, 1998, SEC File No. 001-4300).
10.41	Deed of Guaranty and Indemnity, dated January 11, 2003, made by Registrant in favor of BP Exploration Operating Company Limited (incorporated by reference to Registrant s Current Report on Form 8-K, dated and filed January 13, 2003, SEC File No. 001-4300).
*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 Chief Executive Officer
*31.2	Certification of Chief Financial Officer
*32.1	Certification of Chief Executive Officer and Chief Financial Officer

* Filed 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.

(b) See (a) 3. above.

(c) See (a) 2. above.

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
President, Chief Executive Officer and Chief Operating Officer

Dated: February 28, 2008

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, Rebecca A. Hoyt, and Marc D. Rome, 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	Director, President, Chief Executive Officer and Chief Operating Officer (Principal Executive Officer)	February 28, 2008
/s/ ROGER B. PLANK Roger B. Plank	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ REBECCA A. HOYT Rebecca A. Hoyt	Vice President and Controller (Principal Accounting Officer)	February 28, 2008

Name	Title	Date
/s/ RAYMOND PLANK Raymond Plank	Chairman of the Board	February 28, 2008
/s/ FREDERICK M. BOHEN Frederick M. Bohen	Director	February 28, 2008
/s/ RANDOLPH M. FERLIC Randolph M. Ferlic	Director	February 28, 2008
/s/ EUGENE C. FIEDOREK Eugene C. Fiedorek	Director	February 28, 2008
/s/ A. D. FRAZIER, Jr. A. D. Frazier, Jr.	Director	February 28, 2008
/s/ PATRICIA ALBJERG GRAHAM Patricia Albjerg Graham	Director	February 28, 2008
/s/ JOHN A. KOCUR John A. Kocur	Director	February 28, 2008
/s/ GEORGE D. LAWRENCE George D. Lawrence	Director	February 28, 2008
/s/ F. H. MERELLI F. H. Merelli	Director	February 28, 2008
/s/ RODMAN D. PATTON Rodman D. Patton	Director	February 28, 2008
/s/ CHARLES J. PITMAN Charles J. Pitman	Director	February 28, 2008

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 of 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, 2007. 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, 2007.

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
President, Chief Executive Officer
and Chief Operating Officer

Roger B. Plank
Executive Vice President and Chief Financial Officer

Rebecca A. Hoyt
Vice President and Controller
(Chief Accounting Officer)

Houston, Texas
February 28, 2008

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, 2007 and 2006, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated 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 as of December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As described in Note 1 and Note 9 to the consolidated financial statements, in 2006 the Company adopted the provisions of Statement of Financial Accounting Standards No. 158, Employees Accounting for Defined Benefit Plans and Other Postretirement Plans. In addition, as described in Note 1 to the consolidated financial statements, in 2007 the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes.

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, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Apache Corporation:

We have audited Apache Corporation s internal control over financial reporting as of December 31, 2007, 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 s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 and 2006, and the related consolidated statements of operations, shareholders equity and cash flows for each of the three years in the period ended December 31, 2007, and our report dated February 28, 2008, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 28, 2008

APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31, 2007	2006	2005
	(In thousands, except per common share data)		
REVENUES AND OTHER:			
Oil and gas production revenues	$ 9,961,982	$ 8,074,253	$ 7,457,291
Gain on China divestiture		173,545	
Other	15,876	40,981	126,953
	9,977,858	8,288,779	7,584,244
OPERATING EXPENSES:			
Depreciation, depletion and amortization	2,347,791	1,816,359	1,415,682
Asset retirement obligation accretion	96,438	88,931	53,720
Lease operating expenses	1,705,999	1,362,374	1,040,475
Gathering and transportation	118,034	104,322	100,260
Severance and other taxes	541,982	553,978	453,258
General and administrative	275,065	211,334	198,272
Financing costs, net	219,937	141,886	116,323
	5,305,246	4,279,184	3,377,990
INCOME BEFORE INCOME TAXES	4,672,612	4,009,595	4,206,254
Provision for income taxes	1,860,254	1,457,144	1,582,524
NET INCOME	2,812,358	2,552,451	2,623,730
Preferred stock dividends	5,680	5,680	5,680
INCOME ATTRIBUTABLE TO COMMON STOCK	$ 2,806,678	$ 2,546,771	$ 2,618,050
BASIC NET INCOME PER COMMON SHARE	$ 8.45	$ 7.72	$ 7.96
DILUTED NET INCOME PER COMMON SHARE	$ 8.39	$ 7.64	$ 7.84

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

APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31, 2007	2006	2005
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 2,812,358	$ 2,552,451	$ 2,623,730
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,347,791	1,816,359	1,415,682
Provision for deferred income taxes	889,527	751,457	598,927
Asset retirement obligation accretion	96,438	88,931	53,720
Gain on sale of China operations		(173,545)	
Other	48,966	32,380	52,274
Changes in operating assets and liabilities, net of effects of acquisitions:			
(Increase) decrease in receivables	(261,962)	(153,616)	(504,038)
(Increase) decrease in inventories	39,787	10,238	11,295
(Increase) decrease in drilling advances and other	(30,531)	66,323	(144,154)
(Increase) decrease in deferred charges and other	12,368	(126,869)	(26,454)
Increase (decrease) in accounts payable	(38,923)	(136,663)	97,447
Increase (decrease) in accrued expenses	(169,087)	(475,021)	214,491
Increase (decrease) in deferred credits and noncurrent liabilities	(69,299)	60,481	(60,650)
NET CASH PROVIDED BY OPERATING ACTIVITIES	5,677,433	4,312,906	4,332,270
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(4,322,469)	(3,891,639)	(3,715,856)
Acquisition of BP plc properties		(833,820)	
Acquisition of Pioneer s Argentine operations		(704,809)	
Acquisition of Amerada Hess properties		(229,134)	
Acquisition of Pan American properties		(396,056)	
Acquisition of Anadarko properties	(1,004,593)		
Proceeds from China divestiture		264,081	
Proceeds from sale of Egypt properties		409,203	
Additions to gathering, transmission and processing facilities	(479,874)	(248,589)	
Proceeds from sales of oil and gas properties	67,483	4,740	79,663
Other, net	(206,476)	(149,559)	(95,649)
NET CASH USED IN INVESTING ACTIVITIES	(5,945,929)	(5,775,582)	(3,731,842)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Debt borrowings	3,498,623	1,779,963	153,368

Payments on debt	(3,091,583)	(150,266)	(549,530)
Dividends paid	(204,753)	(154,143)	(117,395)
Common stock activity	29,682	31,963	18,864
Treasury stock activity, net	14,279	(166,907)	6,620
Cost of debt and equity transactions	(18,179)	(2,061)	(861)
Other	25,726	35,791	6,273
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	253,795	1,374,340	(482,661)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(14,701)	(88,336)	117,767
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	140,524	228,860	111,093
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 125,823	$ 140,524	$ 228,860

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

APACHE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 125,823	$ 140,524
Receivables, net of allowance	1,936,977	1,651,664
Inventories	461,211	320,386
Drilling advances	112,840	78,838
Derivative instruments	20,889	139,756
Prepaid assets and other	94,511	159,103
	2,752,251	2,490,271
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full cost accounting:		
Proved properties	34,645,710	29,107,921
Unproved properties and properties under development	1,439,726	1,284,743
Gathering, transmission and processing facilities	2,206,453	1,725,619
Other	416,149	358,605
	38,708,038	32,476,888
Less: Accumulated depreciation, depletion and amortization	(13,476,445)	(11,130,636)
	25,231,593	21,346,252
OTHER ASSETS:		
Goodwill, net	189,252	189,252
Deferred charges and other	461,555	282,400
	$ 28,634,651	$ 24,308,175
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 617,937	$ 644,889
Accrued operating expense	112,453	70,551
Accrued exploration and development	600,165	534,924
Accrued compensation and benefits	172,542	127,779
Accrued interest	78,187	30,878
Accrued income taxes	73,184	2,133

Current debt	215,074	1,802,094
Asset retirement obligation	309,777	376,713
Derivative instruments	286,226	70,128
Other	199,471	151,523
	2,665,016	3,811,612
LONG-TERM DEBT	4,011,605	2,019,831
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	3,924,983	3,618,989
Asset retirement obligation	1,556,909	1,370,853
Derivative instruments	381,791	
Other	716,368	295,837
	6,580,051	5,285,679
COMMITMENTS AND CONTINGENCIES (Note 9)		
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 issued and outstanding	98,387	98,387
Common stock, $0.625 par, 430,000,000 shares authorized, 341,322,088 and 339,783,392 shares issued, respectively	213,326	212,365
Paid-in capital	4,367,149	4,269,795
Retained earnings	11,457,592	8,898,577
Treasury stock, at cost, 8,394,945 and 9,045,967 shares, respectively	(238,264)	(256,739)
Accumulated other comprehensive loss	(520,211)	(31,332)
	15,377,979	13,191,053
	$ 28,634,651	$ 24,308,175

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

APACHE CORPORATION AND SUBSIDIARIES

STATEMENT OF CONSOLIDATED SHAREHOLDERS EQUITY

	Comprehensive Income	Series B Preferred Stock	Common Stock	Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Tota Shareho Equi
				(In thousands)				
NCE AT MBER 31, 2004		$ 98,387	$ 209,320	$ 4,106,182	$ 4,017,339	$ (97,325)	$ (129,482)	$ 8,20
ehensive income								
ome	$ 2,623,730				2,623,730			2,62
odity hedges, net me tax benefit of 90	(236,126)						(236,126)	(23
ehensive income	$ 2,387,604							
vidends:								
ed					(5,680)			(
on ($.36 per					(118,526)			(11
on shares issued			1,303	21,125				2
ry shares issued,				2,736		7,561		1
nsation expense				40,528				4
				143				
NCE AT MBER 31, 2005		98,387	210,623	4,170,714	6,516,863	(89,764)	(365,608)	10,54
ehensive income								
ome	$ 2,552,451				2,552,451			2,55
irement, net of tax benefit of	(6,116)						(6,116)	(
odity hedges, net me tax expense ,162	340,392						340,392	34
ehensive income	$ 2,886,727							
vidends:								

ed					(5,680)			(
on ($.50 per								
					(165,059)			(16
on shares issued			1,742	54,917				5
y shares								
sed, net				1,968		(166,967)		(16
nsation expense				42,085				4
				111	2	(8)		
NCE AT								
MBER 31, 2006		98,387	212,365	4,269,795	8,898,577	(256,739)	(31,332)	13,19
ehensive income								
ome	$ 2,812,358				2,812,358			2,81
irement, net of								
tax expense of								
	6,333						6,333	
odity hedges, net								
me tax benefit of								
65	(495,212)						(495,212)	(49
ehensive income	$ 2,323,479							
vidends:								
ed					(5,680)			(
on ($.60 per								
					(199,401)			(19
on shares issued			961	48,144				4
y shares								
sed, net				1,834		18,475		2
nsation expense				48,816				4
adoption					(48,502)			(4
				(1,440)	240			(
NCE AT								
MBER 31, 2007		$ 98,387	$ 213,326	$ 4,367,149	$ 11,457,592	$ (238,264)	$ (520,211)	$ 15,37

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

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 64 percent 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. In November 2007, the Company announced that it had been awarded two exploration blocks in Chile. The Company is currently finalizing agreements on these blocks with the Chilean government.

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 with the current presentations. 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 interests 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 there from (See Note 12 Supplemental Oil and Gas Disclosure), asset retirement obligations, income taxes, valuation of derivative instruments and contingency obligations including legal and environmental risks and exposures.

Cash Equivalents The Company considers all highly liquid short-term investments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Doubtful Accounts The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. 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 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 both December 31, 2007 and 2006, the Company had an allowance for doubtful accounts of $23 million.

Beginning in 2001, Apache experienced a gradual decline in the timeliness of receipts from EGPC for our Egyptian oil and gas sales. During 2007, the Company experienced wide variability in the timing of cash receipts. Apache has not established a reserve for these Egyptian receivables because the Company continues to get paid, albeit late, and has no indication that it will not be able to collect the receivable.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Property and Equipment 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 $208 million, $146 million and $141 million of these internal costs in 2007, 2006 and 2005, 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 of the Company s proved reserve quantities in a particular country are sold (greater than 25 percent), in which case a gain or loss is recognized.

Costs Excluded Properties and equipment include costs that are excluded from costs being depreciated or amortized. Oil and gas costs excluded 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 or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. 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. In those 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, G&G costs not associated with specific properties are recorded to proved property.

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 (costs to access and develop reserves needing additional facilities, equipment or downhole work in order to produce) and asset retirement costs which are not already included in oil and gas property, less related salvage value.

Buildings, equipment and gas gathering, transmission and processing facilities 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 $720 million and $582 million at December 31, 2007 and 2006, respectively.

Ceiling Test Under the 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 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. The estimate of after-tax future net cash flows is calculated using a discount rate of 10 percent per annum and prices in effect at the end of the period held flat for the life of production, except where future oil and gas sales are covered by physical contract terms or by derivative instruments that qualify, and are accounted for, as cash flow hedges. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional DD&A. See Note 12 - Supplemental Oil and Gas Disclosures (Unaudited) for a discussion on calculation of estimated future net cash flows.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Given the volatility of oil and gas prices, it is reasonably possible that the Company s estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur.

Asset Retirement Obligations The initial estimated retirement obligation of properties is recognized as a liability, with an associated increase in properties 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 asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating asset retirement costs and changes in the estimated timing of settling asset retirement obligations.

Capitalized Interest Cost Interest is capitalized as part of the historical cost of acquiring assets. Oil and gas investments in unproved properties and exploration and development activities which are in progress qualify for capitalized interest. Major construction projects also qualify for interest capitalization until 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. Capitalized interest cannot exceed gross interest expense. As oil and gas costs excluded are transferred to the DD&A pool, any associated capitalized interest is also transferred to the DD&A pool. As major construction projects are completed, the associated capitalized interest is amortized over the useful life of the related asset. Capitalized interest totaled $76 million, $61 million and $57 million in 2007, 2006 and 2005 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 the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Goodwill totaled $189 million at December 31, 2007 and 2006, 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 2007, 2006 or 2005.

Accounts Payable Included in accounts payable at December 31, 2007 and 2006, are liabilities of approximately $125 million and $204 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 underproduced 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 CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, usually up to 40 percent, is available to the contractor partners to recover all operating and capital costs. The balance of the production is split among the contractor partners and Egyptian General Petroleum Corporation (EGPC) on a contractually defined basis.

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 $123 million, $160 million and $158 million, for 2007, 2006 and 2005, respectively.

Derivative Instruments and Hedging Activities Apache periodically enters into derivative contracts to manage its exposure to foreign currency risk and 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 SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. SFAS No. 133 establishes accounting and reporting standards requiring 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 independent parties). SFAS No. 133 also requires that changes in fair value be 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 production revenues when the forecasted transaction occurs. Realized gains and losses on foreign currency cash flow hedges are generally recognized in lease operating expense 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 Revenue 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 under SFAS No. 133 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 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 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 is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 would then reflect 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.

The Company accounts for foreign currency gains and losses in accordance with SFAS No. 52 Foreign Currency Translation. Foreign currency translation gains and losses related to deferred taxes are recorded as a component of its provision for income taxes. The Company recorded additional deferred tax expense of $228 million in 2007, a $5 million deferred tax benefit in 2006 and $13 million of additional deferred tax expense in 2005; (see Note 6 Income Taxes). All other foreign currency 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 a gain of $9 million in 2007, a $15 million loss in 2006 and a gain of $11 million in 2005.

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.

In connection with damage related to Hurricanes Katrina and Rita in 2005, please see Note 9 Commitments and Contingencies for a discussion on the status of claims filed.

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 could occur if options were exercised and if restricted stock were 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.

Stock-Based Compensation The Company accounts for stock-based compensation under the fair value recognition provisions of SFAS No. 123-R, Accounting for Stock-Based Compensation, as amended and revised. The Company grants various types of stock-based awards including stock options, nonvested equity shares (restricted stock) 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, on a straight-line basis over the required service period.

SFAS No. 123-R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow rather than as an operating cash flow. The Company classified $30 million, $49 million and $27 million as financing cash inflows in 2007, 2006 and 2005, respectively.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Recently Issued Accounting Standards Not Yet Adopted

In December 2007, the Financial Accounting Standards Board (FASB) issued a revision to SFAS No. 141 Business Combinations (SFAS No. 141(R)). The revision 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 statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS No. 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. Apache is currently evaluating the provisions of SFAS No. 141(R) and assessing the impact it may have on the Company.

Also in December 2007, the FASB issued SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements. This statement amends Accounting Research Bulletin No. 51, Consolidated Financial Statements. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interests in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the Consolidated Financial Statements. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS No. 160 and assessing the impact it may have on the Company.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to measure various financial instruments and certain other items at fair value. SFAS No. 159 will be effective for the Company in the first quarter of 2008. At the present time, the Company does not expect to apply the provisions of SFAS No. 159.

In September 2006, the FASB issued SFAS No. 157 Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The statement does not require any new fair value measurements for Apache. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 157 is not expected to materially impact the Company s Consolidated Financial Statements; however, it will result in additional disclosures related to the use of fair values in the financial statements.

Also in September 2006, the FASB issued SFAS No. 158 Employers Accounting for Defined Benefit Plans and Other Postretirement Plans. The statement requires employers to recognize any over-funded or under-funded status of a defined benefit postretirement plan as an asset or liability in their Consolidated Financial Statements. Unrealized components of net periodic benefit costs are reflected in other comprehensive income, net of tax. As of the year ended December 31, 2006, Apache adopted the recognition and disclosure requirements of SFAS No. 158. The Company recorded an adjustment to accumulated other comprehensive income in Shareholders Equity of $11 million ($6 million after tax). The adjustment reflects the recognition of the Company s unfunded status for both the Company s pension plan and post retirement benefit plan. Refer to Note 9 Commitments and Contingencies for additional disclosures.

In July 2006, the FASB issued FASB Interpretation No. 48 (FIN 48) Accounting for Uncertainty in Income Taxes . FIN 48 clarifies the accounting for income taxes, by prescribing a minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. The interpretation also provides guidance on derecognizing, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company adopted FIN 48 as of January 1, 2007, as required. As a result of the implementation of FIN 48, the Company recorded a $49 million increase in its tax reserves and an offsetting decrease to retained earnings for uncertain tax positions. As of the adoption date, the Company had total tax reserves

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of $563 million, including $521 million of unrecognized tax benefits which, if recognized, would impact the Company s effective income tax rate in future periods. This reserve includes an estimate of potential interest and penalties, which are recorded as components of income tax expense, in the amount of $91 million as of January 1, 2007. Liabilities related to uncertain tax positions are reflected in Deferred Credits and Other Noncurrent Liabilities under the Other caption. (See Note 6 Income Taxes).

2. ACQUISITIONS AND DIVESTITURES

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. Apache must spend the entire $30 million in qualified expenditures during the initial term or pay the difference as liquidated damages.

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 Petroleum Corporation (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 the natural gas production.

Divestitures In 2007 the Company sold non-strategic oil and gas properties located in northwest Louisiana for approximately $56 million and contracted to sell others for approximately $309 million. The assets under contract are expected to close in the first quarter of 2008.

Subsequent Events On January 29, 2008, the Company completed the sale of its 50 percent interest in Ship Shoal blocks 349 and 369 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 properties in the Permian basin of West Texas and New Mexico to Vanguard Permian, LLC for $78 million.

2006 Activity

U.S. Permian Basin On January 5, 2006, the Company purchased Hess s interest in eight fields located in the Permian basin of West Texas and New Mexico. The original purchase price was reduced from $404 million to $269 million because other interest owners exercised their preferential rights on a number of the properties. The settlement price on the date of closing of $239 million was adjusted primarily for revenues and expenditures occurring between the closing date and the effective date of the acquisition. Apache estimates that these fields had proved reserves of 27 MMbbls of liquid hydrocarbons and 27 Bcf of natural gas as of year-end 2005.

Argentina On April 25, 2006, the Company acquired the operations of Pioneer Natural Resources (Pioneer) in Argentina for $675 million. The settlement price at closing, of $703 million, was adjusted for revenues and expenditures occurring between the effective date and closing date of the acquisition. The properties are located in the Neuquén, San Jorge and Austral basins of Argentina and had estimated net proved reserves of approximately 22 MMbbls of liquid hydrocarbons and 297 Bcf of natural gas as of December 31, 2005. Eight gas processing plants (five operated and three non-operated), 112 miles of operated pipelines in the Neuquén basin and 2,200 square miles of three-dimensional (3-D) seismic data were also included in the transaction. Apache financed the purchase with

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash on hand and commercial paper. The purchase price was allocated to the assets acquired and liabilities assumed based upon the estimated fair values as of the date of acquisition, as follows (in thousands):

Proved property	$ 501,938
Unproved property	189,500
Gas Plants	51,200
Working capital acquired, net	11,256
Asset retirement obligation	(13,635)
Deferred income tax liability	(37,630)
Cash consideration	$ 702,629

On September 19, 2006, Apache acquired additional interests in (and now operates) seven concessions in the Tierra del Fuego Province from Pan American Fueguina S.R.L. (Pan American) for total consideration of $429 million. The settlement price at closing of $396 million was adjusted for normal closing items, including revenues and expenses between the effective date and the closing date of the acquisition. Apache financed the purchase with cash on hand and commercial paper.

The total cash consideration allocated below includes working capital balances purchased, asset retirement obligations assumed and an obligation to deliver specific gas volumes in the future. The purchase price was allocated to the assets acquired and liabilities assumed based upon the estimated fair values as of the date of acquisition, as follows (in thousands):

Proved property	$ 289,916
Unproved property	132,000
Gas plants	12,722
Working capital acquired, net	8,929
Asset retirement obligation	(1,511)
Assumed obligation	(46,000)
Cash consideration	$ 396,056

U.S. Gulf Coast On June 21, 2006, the Company completed its acquisition of the remaining producing properties of BP plc (BP) on the Outer Continental Shelf of the Gulf of Mexico. The original purchase price was reduced from $1.3 billion to $845 million because other interest owners exercised their preferential rights to purchase five of the original 18 producing fields. The settlement price on the date of closing of $821 million was adjusted primarily for revenues and expenditures occurring between the closing date and the effective date of the acquisition. The effective date of the purchase was April 1, 2006. The properties include 13 producing fields (nine of which are operated) with estimated proved reserves of 19.5 MMbbls of liquid hydrocarbons and 148 Bcf of natural gas. Apache financed the purchase with cash on hand and commercial paper.

Divestitures On January 6, 2006, the Company completed the sale of its 55 percent interest in the deepwater section of Egypt s West Mediterranean Concession to Hess for $413 million. Proceeds from the sale were accounted for as a reduction of capitalized costs. Apache did not have any proved reserves booked for these properties.

On August 8, 2006, the Company completed the sale of its 24.5 percent interest in the Zhao Dong block, offshore the People s Republic of China, to Australia-based ROC Oil Company Limited for $260 million, marking Apache s exit from China. The effective date of the transaction was July 1, 2006, and the Company recorded a gain of $174 million in the third quarter of 2006.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2005 Activity

Canadian Exxon Mobil Corporation Farm-in In May, 2005, Apache signed a farm-in agreement with Exxon Mobil Corporation (ExxonMobil) covering approximately 650,000 acres of undeveloped properties in the Western Canadian province of Alberta. Under the agreement, Apache has the right to earn acreage sections by drilling an initial well on each such section. ExxonMobil will retain a royalty on fee lands and a working interest on leasehold acreage. The agreement also allows Apache to test additional horizons on approximately 140,000 acres of property covered in a 2004 farm-in agreement with ExxonMobil.

3. HEDGING AND DERIVATIVE INSTRUMENTS

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its worldwide production. Management 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 to manage fluctuations in cash flows resulting from changes in commodity prices. Derivative instruments typically entered into by the Company, and designated as cash flow hedges, are swaps and options.

As of December 31, 2007, the total outstanding positions of Apache s natural gas and crude oil cash flow hedges were as follows:

Costless Collars

Production Period	Instrument Type	Total Volumes			Weighted Average Floor/Ceiling		Fair Value Asset/(Liability) (In thousands)
2008	US Gas Collars	89,670,000	MMBtu	$	7.24 / 10.28	$	36,029
	Canadian Gas Collars	32,940,000	GJ	$	6.66 / 10.44	$	19,859
	Oil Collars	12,261,000	Bbl	$	63.18 / 76.47	$	(217,201)
2009	US Gas Collars	14,600,000	MMBtu	$	7.06 / 9.91	$	(4,418)
	Canadian Gas Collars	29,200,000	GJ	$	6.58 / 10.22	$	6,865
	Oil Collars	7,861,000	Bbl	$	59.38 / 72.65	$	(131,727)
2010	US Gas Collars	1,350,000	MMBtu	$	7.17 / 10.58	$	(612)
	Oil Collars	5,464,000	Bbl	$	61.15 / 75.10	$	(72,270)
2011	Oil Collars	2,917,000	Bbl	$	63.12 / 76.42	$	(33,509)
2012	Oil Collars	910,000	Bbl	$	64.00 / 76.55	$	(9,939)

Fixed Price Swaps

Production Period	Instrument Type	Total Volumes		Weighted Average Fixed-Price		Fair Value Asset/(Liability) (In thousands)	
2008	Fixed-Price Oil Swap	4,574,500	Bbl	$	70.05	$	(103,223)
2009	Fixed-Price Oil Swap	549,500	Bbl	$	74.32	$	(6,817)
2010	Fixed-Price Oil Swap	2,182,250	Bbl	$	71.98	$	(28,836)
2011	Fixed-Price Oil Swap	3,436,250	Bbl	$	71.79	$	(43,775)
2012	Fixed-Price Oil Swap	2,926,000	Bbl	$	71.34	$	(36,609)
2013	Fixed-Price Oil Swap	1,086,000	Bbl	$	71.34	$	(13,292)

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A costless collar is an option position established by selling a call and purchasing a put. The call establishes a maximum price (ceiling) and the put establishes a minimum price (floor) that will be received for volumes under contract. The fixed-price swaps establish a set price the Company will receive for volumes under contract.

U.S. natural gas prices in the table above represent a weighted average of several contracts entered into on a per million British thermal units (MMBtu) basis and are settled against a combination of indices, including NYMEX Henry Hub, Panhandle Eastern Pipe Line and Houston Ship Channel. The Canadian natural gas prices in the table above represent a weighted average of AECO Index prices. These gas collars are entered into on a per gigajoule (GJ) basis, are converted to U.S. dollars utilizing a December 31, 2007 exchange rate, and are settled against the AECO Index. Crude oil prices in the table above primarily represent a weighted average of NYMEX Cushing Index prices on contracts entered into on a per barrel (Bbl) basis. These crude oil contracts are settled primarily against the NYMEX Cushing index.

The contracts entered into by the Company are valued using actively quoted prices and quotes obtained from reputable third-party financial institutions. The Company has exposure to credit risk to the extent the counterparty to the contract is unable to meet its settlement commitment. Apache actively monitors the creditworthiness of each counterparty and assesses the impact, if any, on the Company s derivative positions. In addition, the Company may exercise its right to net realized gains against realized losses when settling its swap and options positions with a counterparty.

A reconciliation of the components of accumulated other comprehensive income (loss) in the Statement of Consolidated Shareholders Equity related to Apache s commodity derivative activity is presented in the table below:

	Gross	After Tax
	(In thousands)	
Unrealized gain (loss) on derivatives at December 31, 2006	$ 129,325	$ 83,534
Net losses realized into earnings	32,635	19,965
Net change in derivative fair value	(800,712)	(515,177)
Unrealized gain (loss) on derivatives at December 31, 2007	$ (638,752)	$ (411,678)

Differences between the fair values and the unrealized loss on derivatives before income taxes recognized in accumulated other comprehensive income (loss) are related to premiums, recognition of unrealized gains and losses on certain derivatives that did not qualify for hedge accounting and hedge ineffectiveness. Based on market prices as of December 31, 2007, the Company recorded an unrealized loss in other comprehensive income of $639 million ($412 million after tax). Unrealized gains and losses on these commodity hedges will fluctuate significantly and will ultimately be realized in future earnings contemporaneously with the related sales of natural gas and crude oil production applicable to specific hedges. Of the $639 million estimated unrealized loss on derivatives at December 31, 2007, approximately $264 million ($169 million after tax) applies to the next 12 months; however, estimated and actual amounts are likely to vary materially as a result of changes in market conditions. These contracts, designated as hedges, qualified and continue to qualify for hedge accounting in accordance with SFAS No. 133, as amended.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ASSET RETIREMENT OBLIGATION

The following table is a reconciliation of the asset retirement obligation liability:

	2007	2006
	(In thousands)	
Asset retirement obligation at beginning of year	$ 1,747,566	$ 1,455,915
Liabilities incurred	243,284	298,899
Liabilities settled	(480,655)	(306,945)
Accretion expense	96,438	88,931
Revisions in estimated liabilities	260,053	210,766
Asset retirement obligation at end of year	1,866,686	1,747,566
Less current portion	309,777	376,713
Asset retirement obligation, long-term	$ 1,556,909	$ 1,370,853

The majority of Apache s asset retirement obligations (ARO) relate to plugging, abandonment and restoration of oil and gas properties. An abandonment liability is initially recorded in the period the related assets are placed in service, with an offsetting increase to properties and equipment. The liabilities incurred are recorded at fair value, and accretion expense is recognized over the life of the related assets, increasing the liability to its expected settlement value. Liabilities settled relate to individual properties plugged and abandoned or sold during the period and includes the continued abandonment activity of platforms lost during Hurricanes Katrina and Rita. Revisions in estimated liabilities during the period primarily related to escalating retirement costs, changes in property lives and the expected timing of settling asset retirement obligations.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. DEBT

	December 31, 2007	December 31, 2006
	(In millions)	
Apache:		
Money market lines of credit	$ 4	$ 11
Commercial paper	135	1,560
6.25% debentures due 2012	400	400
5.25% notes due 2013	500	
5.625% notes due 2017	500	
7% notes due 2018	150	150
7.625% notes due 2019	150	150
7.7% notes due 2026	100	100
7.95% notes due 2026	180	180
6% notes due 2037	1,000	
7.375% debentures due 2047	150	150
7.625% debentures due 2096	150	150
	3,419	2,851
Subsidiary and other obligations:		
Argentina money market lines of credit	76	59
Notes due in 2008, 2016 and 2017	1	4
Apache Finance Australia 6.5% notes due 2007		170
Apache Finance Australia 7% notes due 2009	100	100
Apache Finance Canada 4.375% notes due 2015	350	350
Apache Finance Canada 7.75% notes due 2029	300	300
	827	983
Total debt	4,246	3,834
Less:		
Unamortized discount	(19)	(12)
Current maturities	(215)	(1,802)
Total long-term debt	$ 4,012	$ 2,020

All of the Company s debt is senior unsecured debt and has equal priority with respect to the payment of both principal and interest. The 6.25%, 5.25%, 5.625% and 6% notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The remaining U.S. notes are not redeemable. Under certain conditions, the

Company has the right to advance maturity on the 7.375% debentures and 7.625% debentures.

The Company has $19 million of debt discounts as of December 31, 2007, that will be charged to interest expense over the life of the related debt issuances; $1 million, $714,000 and $668,000 was recognized in 2007, 2006 and 2005, respectively.

As of December 31, 2007 and 2006, the Company had approximately $33 million and $21 million, respectively, of unamortized deferred loan costs associated with its various debt obligations. These costs are included in deferred charges and other in the accompanying consolidated balance sheet and are being charged to expense over the life of the related debt issuances.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The indentures for the notes described above place certain restrictions on the Company, including limits on Apache s ability to incur debt secured by certain liens and its ability to enter into certain sale and leaseback transactions. Upon certain change in control, all of these debt instruments would be subject to mandatory repurchase, at the option of the holders. None of the indentures for the notes contain pre-payment obligations in the event of a decline in credit ratings.

Debt Issuances

On January 26, 2007, the Company issued $500 million principal amount, $499.5 million net of discount, of senior unsecured 5.625% notes maturing January 15, 2017 and $1.0 billion principal amount, $993 million net of discount, of senior unsecured 6% notes maturing January 15, 2037. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay a portion of the Company s commercial paper outstanding in anticipation of funding our $1 billion acquisition of Permian basin properties from Anadarko which closed March 29, 2007, and for general corporate purposes.

On April 16, 2007, the Company issued $500 million principal amount, $498.8 million net of discount, of senior unsecured 5.25% notes maturing April 15, 2013. The notes are redeemable, as a whole or in part, at Apache s option, subject to a make-whole premium. The proceeds were used to repay a portion of the Company s outstanding commercial paper and for general corporate purposes.

The Company has certain uncommitted money market lines of credit which are used from time to time for working capital purposes. As of December 31, 2007, $76 million was drawn on facilities in Argentina and $4 million was drawn on U.S. facilities, compared with $59 million and $11 million in the prior year.

The Company has a $1.95 billion commercial paper program which enables Apache to borrow funds for up to 270 days at competitive interest rates. As of December 31, 2007, the Company had issued $135 million of commercial paper at a weighted-average interest rate of 5.32%, compared to $1.6 billion at 5.15% in the prior year. The commercial paper is fully supported by available borrowing capacity under U.S. committed credit facilities which expire in 2012. Any commercial paper issued reduces available borrowing capacity under our U.S. credit facilities.

Debt Repayments

The $170 million Apache Finance Pty Ltd (Apache Finance Australia) 6.5% notes matured on December 17, 2007. The notes were repaid using funds borrowed under Apache s commercial paper program.

Subsidiary Debt

The notes issued by Apache Finance Australia and Apache Finance Canada are irrevocably and unconditionally guaranteed by Apache and, in the case of Apache Finance Australia, by Apache North America, Inc., an indirect wholly-owned subsidiary of the Company. Under certain conditions related to changes in relevant tax laws, Apache Finance Australia and Apache Finance Canada have the right to redeem the notes prior to maturity. The Apache Finance Canada 4.375% notes may be redeemed at the Company s option subject to a make-whole premium (see Note 14 Supplemental Guarantor Information).

Credit Facilities

On April 30, 2007, the Company amended its existing $1.5 billion U.S. five-year revolving credit facility to extend the maturity date one year to May 28, 2012. The amendment also allows the Company to increase the size of the facility by up to $750 million by adding commitments from new or existing lenders.

The Company also amended its $450 million U.S. credit facility, $150 million Australian credit facility and $150 million Canadian credit facility to extend the maturity dates of all the commitments to May 12, 2012. The

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

amendment also allows the Company to increase the size of the U.S. facility by up to $250 million, the Australian facility by up to $150 million and the Canadian facility by up to $150 million by adding commitments from new or existing lenders.

The Company currently has $2.25 billion of syndicated bank credit facilities, of which $2.1 billion was available at December 31, 2007. 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., Canada and Australia of up to five percent of the Company s consolidated assets, which approximated $1.4 billion as of December 31, 2007. There are no restrictions on incurring liens in countries other than the U.S., Canada and Australia. 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., Canadian and Australian subsidiaries, defaults on any direct payment obligation in excess of $100 million or has any unpaid, non-appealable judgment against it in excess of $100 million. The Company was in compliance with the terms of the credit facilities as of December 31, 2007. The Company s debt-to-capitalization ratio as of December 31, 2007 was 22 percent.

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. The $1.5 billion and the $450 million credit facilities (U.S. credit facilities) also allow the Company to borrow under competitive auctions.

At December 31, 2007, 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. The U.S. credit facilities are used to support Apache s commercial paper program.

Credit Ratings

Apache s senior unsecured long-term debt is currently rated A3 by Moody s, A- by Standard & Poor s and A by Fitch. Apache s short-term debt rating for its commercial paper program is currently P-2 by Moody s, A-2 by Standard & Poor s and F1 by Fitch. The outlook is stable from all three rating agencies.

APACHE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Aggregate Maturities of Debt

		(In millions)
2008	$	215
2009		100
2010		
2011		
2012		399
Thereafter		3,513