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

FORM 10-K

(Mark One)

☑	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the fiscal year ended December 31, 2009

OR

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

Commission File Number 0-13546

APACHE OFFSHORE INVESTMENT PARTNERSHIP

Delaware	**41-1464066**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400
(Address of principal executive offices)

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

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: Partnership Units

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 o No ☑

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

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 ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T ((§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o 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 definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2009	$10,434,732

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Apache Corporation's proxy statement relating to its 2010 annual meeting of stockholders have been incorporated by reference into Part III hereof.

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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) or billion cubic feet (Bcf). 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 (bopd) and thousands of cubic feet of gas per day (Mcfd), respectively. With respect to information relating to the Partnership's working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by the Partnership's working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEM 1. BUSINESS

General

Apache Offshore Investment Partnership, a Delaware general partnership (the Investment Partnership), was formed on October 31, 1983, consisting of Apache Corporation, a Delaware corporation, (Apache or Managing Partner), as Managing Partner and public investors (the Investing Partners). The Investment Partnership invested its entire capital in Apache Offshore Petroleum Limited Partnership, a Delaware limited partnership (the Operating Partnership), of which Apache is the sole general partner and the Investment Partnership is the sole limited partner. The primary business of the Investment Partnership is to serve as the sole limited partner of the Operating Partnership. The primary business of the Operating Partnership is to conduct oil and gas exploration, development and production operations. The Operating Partnership conducts the operations of the Investment Partnership.

The Investment Partnership does not maintain its own website. However, copies of this Form 10-K and the Partnership's periodic filings with the Securities and Exchange Commission (SEC) can be found on the Managing Partner's website at www.apachecorp.com/Offshore_Investment_Partnership. The Investment Partnership will also provide paper copies of these filings, free of charge, to anyone so requesting. Included in the Investment Partnership's annual reports on Form 10-K and quarterly reports on Form 10-Q are the certifications of the Managing Partners' principal executive officer and principal financial officer that are required by applicable laws and regulations. Any requests to the Partnership for copies of documents filed with the SEC should be made by mail to Apache Offshore Investment Partnership, 2000 Post Oak Blvd., Houston, Texas 77056, Attention: Glenn Hitchcock, or by telephone at 713-296-7097. The Partnership's 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.

The Investing Partners purchased Units of Partnership Interests (Units) in the Investment Partnership at $150,000 per Unit, with five percent down and the balance in payments as called by the Investment Partnership. As of December 31, 2009, a total of $85,000 had been called for each Unit. In 1989, the Investment Partnership determined that the full $150,000 per Unit was not needed, fixed the total calls at $85,000 per Unit, and released the Investing Partners from liability for future calls. The Investment Partnership invested, and will continue to invest, its entire capital in the Operating Partnership. As used hereafter, the term "Partnership" refers to either the Investment Partnership or the Operating Partnership, as the case may be.

The Partnership's business is participation in oil and gas exploration, development and production activities on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. Except for the Matagorda Island Block 681 and 682 interests, as described below, the Partnership acquired its oil and gas interests through the purchase of 85 percent of the working interests held by Apache as a participant in a venture (the Venture) with Shell Oil Company (Shell) and certain other companies. The Partnership owns working interests ranging from 6.29 percent to 7.08 percent in the Venture's properties.

The Venture acquired substantially all of its oil and gas properties through bidding for leases offered by the federal government. The Venture members relied on Shell's knowledge and expertise in determining bidding strategies for the acquisitions. When Shell was successful in obtaining the properties, it generally billed participating members on a promoted basis (one-third for one-quarter) for the acquisition of exploratory leases and on a straight-up basis for the acquisition of leases defined as drainage tracts. All such billings were proportionately reduced to each member's working interest.

In November 1992, Apache and the Partnership formed a joint venture to acquire Shell's 92.6 percent working interest in Matagorda Island Blocks 681 and 682 pursuant to a jointly-held contractual preferential right to purchase. Apache and the Partnership previously owned working interests in the blocks equal to 1.109 percent and 6.287 percent, respectively, and net revenue interests of .924 percent and 5.239 percent, respectively. To facilitate the acquisition, Apache and the Partnership contributed all of their interests in Matagorda Island Blocks 681 and 682 to a newly formed joint venture, and Apache contributed $64.6 million ($55.6 million net of purchase price adjustments) to the joint venture to finance the acquisition. The Partnership had neither the cash nor additional financing to fund a proportionate share of the acquisition and participated through an increased net revenue interest in the joint venture.

Under the terms of the joint venture agreement, the Partnership's effective net revenue interest in the Matagorda Island Block 681 and 682 properties increased to 13.284 percent as a result of the acquisition, while its working interest was unchanged. The acquisition added approximately 7.5 Bcf of natural gas and 16 Mbbls of oil to the Partnership's reserve base without any incremental expenditures by the Partnership.

Since the Venture is not expected to acquire any additional exploratory acreage, future acquisitions, if any, will be confined to those leases defined as drainage tracts. The current Venture members would pay their proportionate share of acquiring any drainage tracts on a non-promoted basis.

Offshore exploration differs from onshore exploration in that production from a prospect generally will not commence until a sufficient number of productive wells have been drilled to justify the significant costs associated with construction of a production platform. Exploratory wells usually are drilled from mobile platforms until there are sufficient indications of commercial production to justify construction of a permanent production platform.

On an ongoing basis, the Partnership reviews the possible sale of lower value properties prior to incurring associated dismantlement and abandonment costs.

Apache, as Managing Partner, manages the Partnership's operations. Apache uses a portion of its staff and facilities for this purpose and is reimbursed for actual costs paid on behalf of the Partnership, as well as for general, administrative and overhead costs properly allocable to the Partnership.

2009 Results and Business Development

The Partnership reported net income in 2009 of $1.3 million, or $867 per Investing Partner Unit. Earnings were down $4.0 million from 2008 on lower oil and gas prices. Natural gas production averaged 1,455 Mcf per day in 2009, while oil sales averaged 98 barrels per day. The Partnership's oil and gas production increased 17 percent and 14 percent, respectively, from 2008 largely as a result of successful recompletions in 2009 and the second half of 2008.

The Partnership participated in two successful recompletions in the North Padre Island 969/976 Field and one successful recompletion in the Matagorda 681/682 Field during 2009. The recompletions, combined with workovers in 2009 and recompletions in the second half of 2009, increased production from 2008.

Based on preliminary information provided by the operators of the properties in which the Partnership owns interests, the Partnership anticipates capital expenditures will total approximately $3 million in 2010 for drilling at Ship Shoal 258/259 and recompletions at South Timbalier 295 and North Padre Island 969/976. Such estimates may change based on realized oil and gas prices, drilling results, rates charged by drilling contractors or changes by the operator to the development plan.

Since inception, the Partnership has acquired an interest in 49 prospects. As of December 31, 2009, 45 of those prospects have been surrendered or sold. As of December 31, 2009, the Partnership had 37 producing wells on the Partnership's four remaining developed fields. Four of the Partnership's producing wells are dual completions. The Partnership had, at December 31, 2009, estimated proved oil and gas reserves of 5.8 Bcfe.

Marketing

Apache, on behalf of the Partnership, seeks and negotiates oil and gas marketing arrangements with various marketers and purchasers. The objective is to maximize the value of the crude oil or natural gas sold by identifying the best markets and most economical transportation routes available to move the oil or natural gas. The oil contracts are generally thirty (30) day evergreen contracts and renew automatically until cancelled by either party. The Partnership's oil and condensate production during 2009 was purchased largely by Shell Trading Company at market prices.

The Managing Partner markets the Partnership's and its own U.S. natural gas production. Most of Apache's and the Partnership's natural gas is sold on a monthly basis at either monthly or daily market prices. The Partnership believes that the sales prices it receives for natural gas sales are market prices.

See Note (5) "Major Customer and Related Parties Information" to the Partnership's financial statements under Item 8. Because the Partnership's oil and gas products are commodities and the prices and terms of its sales reflect those of the market, the Partnership does not believe that the loss of any customer would have a material adverse affect on the Partnership's business or results of operations.

ITEM 1A. RISK FACTORS

The Partnership's business activities are subject to significant hazards and risks, including those described below. If any of such events should occur, the Partnership's business, financial condition, liquidity and/or results of operations could be materially harmed, and holders of the Partnership Units could lose part or all of their investments.

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

The U.S. and other world economies are slowly recovering from a recession that began in 2008 and extended into 2009. Growth has resumed but is modest. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than we have experienced in recent years. In addition, more volatility may occur before a sustainable growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for the Partnership's crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results.

The Partnership's revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2009 ranged from a high of $81.37 per barrel to a low of $33.98 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu. The market prices for crude oil and natural gas depend on factors beyond the Partnership's control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions, and other factors, including:

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

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

- limiting our financial condition, liquidity, and/or ability to fund planned capital expenditures and operations;
- reducing the amount of crude oil and natural gas that we can produce economically;

- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income and cash flows;
- a reduction in the carrying value of our crude oil and natural gas properties; or

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

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

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

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

Declining commodity prices may require the Partnership to reduce capital expenditures or distributions to partners, or both, as cash from operating activities decline.

The Partnership is not likely to make a distribution in the first quarter of 2010 as a result of capital outlays for drilling in Ship Shoal 258/259 and recompletions in South Timbalier 295. If commodity prices remain at or decline from levels realized in 2009, the Partnership may not be able to make any distributions to Investing Partners during 2010. Declines in cash from operating activities may reduce funds available for capital expenditures.

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

The Partnership is exposed to risk of financial loss from trade, joint venture and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of our purchasers and non-operating partners may experience liquidity problems and may not be able to meet their financial obligations. Nonperformance by a trade creditor or non-operating partner could result in significant financial losses.

The Partnership may not realize an adequate return on its drilling activities.

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 participate in may not be productive and we may not recover all or any portion of our investment in those wells. 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, blow-outs and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions; and

- increase in cost of, or shortages or delays in the delivery of equipment.

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

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

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value, including factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. In accordance with the SEC's revisions to rules for oil and gas reserves reporting, which the Partnership adopted effective December 31, 2009, our reserves estimates are based on 12-month average prices, except where contractual arrangements exist; therefore, reserves quantities will change when actual prices increase or decrease. The estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies, including the impact of the SEC's new oil and gas company reserves reporting requirements;
- assumptions concerning future crude oil and natural gas prices;
- future operating costs;
- development costs; and
- workover and remediation costs.

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

The Partnership may incur significant costs related to environmental matters.

As an owner or lessee of interests in oil and gas properties, the Partnership is subject to various federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Our efforts to limit our exposure to such liability and cost may prove inadequate and result in significant adverse affect on our results of operations.

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

Our 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. Such regulations may adversely impact our results on operations.

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

Legislation is pending in the United States, that, if enacted, could tax or assess some form of greenhouse gas (GHG) related fees on the Partnership's operations and could lead to increased operating expenses. Such legislation, if enacted, could also potentially cause the Partnership to make significant capital investments for infrastructure modifications.

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

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

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

Proposed federal regulation regarding hydraulic fracturing could increase our operating and capital costs.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas to migrate toward the well-bore. It is typically done at substantial depths in very tight formations.

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

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

Other companies operate the properties in which we have an interest. The Partnership has 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 projected costs and future cash flow.

The Partnership faces significant industry competition.

The Partnership is a very minor participant in the oil and gas industry in the Gulf of Mexico area and faces strong competition from much larger producers for the marketing of its oil and gas. The Partnership's ability to compete for purchasers and favorable marketing terms will depend on the general demand for oil and gas from Gulf of Mexico producers. More particularly, it will depend largely on the efforts of Apache to find the best markets for the sale of the Partnership's oil and gas production.

Insurance policies do 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. The insurance coverage that we maintain against certain losses or liabilities arising from our operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to us against all operational risks.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The Partnership had no comments from the staff of the SEC that were unresolved as of the date of filing of this report.

ITEM 2. PROPERTIES

Acreage

Acreage is held by the Partnership pursuant to the terms of various leases on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. The Partnership does not anticipate any difficulty in retaining any of its leases. A summary of the Partnership's gross and net acreage as of December 31, 2009, is set forth below:

		Developed Acreage	
Lease Block	State	Gross Acres	Net Acres
Ship Shoal 258, 259	LA	10,141	638
South Timbalier 276, 295, 296	LA	15,000	1,063
North Padre Island 969, 976	TX	10,080	714
Matagorda Island 681, 682	TX	10,840	681
		46,061	3,096

At December 31, 2009, the Partnership did not have an interest in any undeveloped acreage.

Productive Oil and Gas Wells

The number of productive oil and gas wells in which the Partnership had an interest as of December 31, 2009, is set forth below:

		Gas		Oil	
Lease Block	State	Gross	Net	Gross	Net
Ship Shoal 258, 259	LA	7	.44	—	—
South Timbalier 276, 295, 296	LA	1	.07	19	1.35
North Padre Island 969, 976	TX	6	.43	—	—
Matagorda Island 681, 682	TX	4	.25	—	—
		18	1.19	19	1.35

Net Wells Drilled

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

	Net Exploratory			Net Development		
Year	Productive	Dry	Total	Productive	Dry	Total
2009	—	—	—	—	—	—
2008	—	—	—	—	.07	.07
2007	—	—	—	—	—	—

Production and Pricing Data

The following table provides, for each of the last three fiscal years, oil, natural gas liquids (NGLs) and gas production for the Partnership, average production costs (including gathering and transportation expense) and average sales prices.

Year Ended December 31,	Production Oil (Mbbls)	Production NGLs (Mbbls)	Production Gas (MMcf)	Average Lease Operating Cost per Mcfe	Average Sales Price Oil (Per bbl)	Average Sales Price NGLs (Per bbl)	Average Sales Price Gas (Per Mcf)
2009							
South Timbalier 295	34	4	61	$ 1.57	$ 57.25	$ 31.90	$ 4.04
Other fields	2	2	470	2.19	64.36	32.35	3.87
Total	36	6	531	$ 1.96	$ 57.60	$ 32.07	$ 3.89
2008							
South Timbalier 295	29	3	54	$ 1.69	$ 110.58	$ 59.85	$ 9.24
Other fields	2	3	414	1.83	111.25	60.94	8.89
Total	31	6	468	$ 1.78	$ 110.61	$ 60.32	$ 8.93
2007							
South Timbalier 295	42	3	81	$ 1.17	$ 74.33	$ 41.03	$ 7.77
Other fields	3	7	474	2.04	70.21	47.18	6.99
Total	45	10	555	$ 1.69	$ 74.07	$ 45.05	$ 7.10

The South Timbalier 295 field contains more than 15 percent of the Partnership's proved reserved, expressed on an oil-equivalent-barrels basis. No other field contained 15 percent or more of the Partnership's proved reserves as of December 31, 2009.

Estimated Proved Reserves and Future Net Cash Flows

In January 2009, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting" (Release 33-8995), amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures. In January 2010 the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, "*Oil and Gas Reserve Estimation and Disclosures*" (ASU 2010-03), which amends Accounting Standards Codification (ASC) Topic 932, "*Extractive Industries—Oil and Gas*" to align the guidance with the changes made by the SEC. The Partnership adopted Release 33-8995 and the amendments to ASC Topic 932 resulting from ASU 2010-03 (collectively, the Modernization Rules) effective December 31, 2009.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGL's that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations. Reserve estimates are considered proved if they are economical producible and are supported by either actual production or conclusive formation tests. Estimated reserves that can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

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

As of December 31, 2009, the Partnership had total estimated proved reserves of 474,384 barrels of crude oil and condensate, 80,566 barrels of NGLs and 2.4 Bcf of natural gas. Combined, these total estimated proved reserves are equivalent to 5.8 Bcf of gas. The Partnership has elected not to disclose probable and possible reserves or reserve estimates based upon futures or other prices in this filing.

The following table shows proved oil, NGL and gas reserves as of December 31, 2009, based on commodity average prices in effect on the first day of each month in 2009, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms.

	Oil (Mbbls)	NGL (Mbbls)	Gas (MMcf)
Proved developed	474	81	2,322
Proved undeveloped	—	—	105
Total proved	474	81	2,427

The Partnership's estimates of proved reserves and proved developed reserves at December 31, 2009, 2008 and 2007, changes in estimated proved reserves during the last three years, and estimates of future net cash flows and discounted future net cash flows from proved reserves are contained in the Supplemental Oil and Gas Disclosures (Unaudited) in the 2009 Consolidated Financial Statements under Item 8 of this Form 10-K. Estimated future net cash flows as of December 31, 2009 were calculated using a discount rate of 10 percent per annum, end of period costs, and average commodity prices in effect on the first day of each month in the 2009, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. Future net cash flows as of December 31, 2008, and 2007, were estimated using commodity prices in effect at the end of those years, in accordance with the SEC guidelines in effect prior to the issuance of the Modernization Rules.

As of December 31, 2009, the Partnership had one undrilled location classified as proved undeveloped. The location is in North Padre Island 969/976 and is scheduled to be drilled within the next five years. The Partnership carried proved undeveloped reserves of 0.1 Bcf at both December 31, 2009 and 2008.

The volumes of 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 annually and revised, either upward or downward, as warranted by additional performance data.

The Partnership's estimate of proved oil and gas reserves are prepared by Ryder Scott Company, L.P. Petroleum Consultants utilizing oil and gas price data and cost estimates provided by Apache as Managing Partner. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. A copy of Ryder Scott's report on the Shell Offshore Venture, of which the partnership owns approximately 85 percent, is filed as an exhibit to this Form 10-K.

The primarily technical person responsible for overseeing the preparation of the Partnership's reserve estimates is Mr. Michael F. Stell, a Managing Senior Vice President with Ryder Scott. Mr. Stell has almost 30 years of industry experience and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

At least annually, each property is reviewed in detail by Apache's centralized and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends and development timing are reasonable. Apache's engineers furnish this information and estimates of dismantlement and abandonment cost to Ryder Scott for their consideration in preparing the Partnership's reserve reports. The internal property reviews and collection of data provided to Ryder Scott is overseen by Apache's Executive Vice President of Corporate Reservoir Engineering.

ITEM 3. LEGAL PROCEEDINGS

There are no material legal proceedings pending to which the Partnership is a party or to which the Partnership's interests are subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during 2009.

PART II

ITEM 5. MARKET FOR THE PARTNERSHIP’S SECURITIES AND RELATED SECURITY HOLDER MATTERS

As of December 31, 2009, there were 1,021.5 of the Partnership’s Units outstanding held by 866 Investing Partners of record. The Partnership has no other class of security outstanding or authorized. The Units are not traded on any security market. No distributions were made to Investing Partners during 2009, while approximately $5.7 million, or $5,500 per Unit, was paid during 2008.

As discussed in Item 7, an amendment to the Partnership Agreement in February 1994, created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash.

On June 6, 2008, certain affiliates of MacKenzie Patterson Fuller, LP (Purchasers) announced a tender offer to purchase up to 207 Units for $13,850 per Unit, less the amount of any distributions declared or made with respect to the Units between June 6, 2008 and July 18, 2008 (the offer expiration date). After resolution of an issue regarding an improperly submitted Unit, the offer resulted in the tender, and the acceptance for payment by the Purchasers, of a total of 6.1728 Units. Upon completion of the offer, the Purchasers hold an aggregate of 6.1728 Units, or approximately 0.6 percent of the total Investing Partner outstanding Units.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data for the five years ended December 31, 2009, should be read in conjunction with the Partnership’s financial statements and related notes included under Item 8 below of this Form 10-K.

	As of or For the Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per Unit amounts)				
Total assets	$ 8,236	$ 6,680	$ 8,308	$ 8,629	$ 11,624
Partners’ capital	$ 6,086	$ 5,191	$ 6,960	$ 7,625	$ 10,311
Oil and gas sales	$ 4,311	$ 7,928	$ 7,679	$ 10,255	$ 14,779
Net income	$ 1,332	$ 5,335	$ 4,834	$ 7,149	$ 11,048
Net income allocated to:					
Managing Partner	$ 447	$ 1,229	$ 1,146	$ 1,702	$ 2,555
Investing Partners	885	4,106	3,688	5,447	8,493
	$ 1,332	$ 5,335	$ 4,834	$ 7,149	$ 11,048
Net income per Investing Partner Unit	$ 867	$ 3,976	$ 3,531	$ 5,178	$ 8,048
Cash distributions per Investing Partner Unit	$ —	$ 5,500	$ 4,000	$ 7,500	$ 9,000

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

Overview

The Partnership's business is participation in oil and gas exploration, development and production activities on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. The Partnership is a very minor participant in the oil and gas industry and faces strong competition in all aspects of its business. With a relatively small amount of capital invested in the Partnership and management's decision to avoid incurring debt, the Partnership has not engaged in acquisition or exploration activities in recent years. The Partnership has not carried any debt since January 1997. The limited amount of capital and the Partnership's modest reserve base, have contributed to the Partnership's focus on production activities and development of existing leases.

The Partnership derives its revenue from the production and sale of crude oil, natural gas and natural gas liquids (NGLs). The Partnership sells its production at market prices and has not used derivative financial instruments or otherwise engaged in hedging activities. Oil and natural gas prices realized by the Partnership fell significantly from amounts realized in 2008, falling 48 percent and 56 percent, respectively, in line with market prices in the U.S. Commodity prices remain volatile and have at times fluctuated significantly from month to month. This volatility has caused the Partnership's revenues and resulting cash flow from operating activities to fluctuate widely over the years. The Partnership's oil and gas production increased slightly in 2009 from 2008, but had declined in each of the two prior years as a result of the Partnership's limited capital expenditures.

The Partnership participates in development drilling and recompletion activities as recommended by outside operators and the Partnership's Managing Partner. The Partnership participated in two successful recompletions in the North Padre Island 969/976 Field and one successful recompletion in the Matagorda 681/682 Field during 2009.

Generally, the Partnership has used its available cash to fund distributions to its Partners. Reflecting the significant impact of lower oil and gas prices on net income and cash from operating activities during 2009, no distributions to Investing Partners were made during 2009. Distributions to Investing Partners totaled $5,500 per Unit in 2008 and $4,000 per Unit in 2007.

The Partnership is not likely to make a distribution in the first quarter of 2010 as the Partnership plans to participate in drilling four wells at Ship Shoal 258/259 during 2010. The amount of distributions for the remainder of 2010 will be dependent upon oil and gas prices realized by the Partnership for the sale of its production and the level of drilling and recompletion activity during 2010.

Results of Operations

This section includes a discussion of the Partnership's results of operations, and items contributing to changes in revenues and expenses during 2009, 2008, and 2007.

Net Income and Revenue

The Partnership reported net income of $1.3 million for 2009, down 75 percent from 2008 on lower oil and gas prices. Net income per Investing Partner Unit decreased in 2009 to $867, down from $3,976 in 2008. The Partnership reported earnings of $5.3 million in 2008 and $4.8 million in 2007.

Total revenues in 2009 of $4.3 million decreased $3.7 million from 2008 as a result of lower oil and gas prices. Interest income earned by the Partnership on short-term cash investments in 2009 of $229 decreased significantly from 2008 as a result of lower cash balances and interest rates in 2009. Interest income totaled $46,193 in 2008 and $104,274 in 2007.

The Partnership's revenues are sensitive to changes in prices received for its products. A substantial portion of the Partnership's production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. Imbalances in the supply and demand for oil and natural gas can have dramatic effects on the prices we receive for our production. Political instability and availability of alternative fuels could impact worldwide supply, while other economic factors could impact demand.

Declines in oil and gas production can be expected in future years as a result of normal depletion. Given the small number of producing wells owned by the Partnership, and the fact that offshore wells tend to decline at a faster rate than onshore wells, the Partnership's future production will be subject to more volatility than those companies with greater reserves and longer-lived properties. It is not anticipated that the Partnership will acquire any additional exploratory leases or that significant drilling will take place on leases in which the Partnership currently holds interests.

The Partnership's oil and gas production volume and price information is summarized in the following table:

	For the Year Ended December 31,		
	2009	2008	2007
Gas volumes – Mcf per day	1,455	1,277	1,520
Average gas price – per Mcf	$ 3.89	$ 8.93	$ 7.10
Oil volumes – barrels per day	98	84	122
Average oil price – per barrel	$57.60	$110.61	$74.07
NGL volumes – barrels per day	16	16	26
Average NGL price – per barrel	$32.07	$ 60.32	$45.05

Natural Gas Sales

2009 vs. 2008 The Partnership's natural gas sales in 2009 totaled $2.1 million or 51 percent less than reported in 2008. During 2009, the partnership's average realized natural gas price declined $5.04 per Mcf, or 56 percent, from 2008 and reduced sales by nearly $2.4 million. Production increases from 2008 offset $0.2 million of the impact of lower prices. Average daily production in 2009 increased 14 percent from 2008, rising to 1,455 Mcf per day in 2009. The increase in natural gas volumes reflected successful recompletions at Matagorda Island 681/682 during the second half of 2008 and at North Padre Island 969/976 during 2009, successful workover projects performed in 2009, and reduced downtime for inclement weather. Further increase in production was thwarted by the downtime at Matagorda Island 681/682 during 2009 for third-party pipeline repairs.

2008 vs. 2007 The Partnership's natural gas sales in 2008 of $4.2 million increased six percent from the same period in 2007. During 2008, the Partnership's average realized gas price increased 26 percent or $1.83 per Mcf over the same period in 2007, rising to $8.93 per Mcf. With extended downtime resulting from Hurricanes Gustav and Ike and natural depletion, the Partnership's natural gas production declined 16 percent from 2007 to a daily average of 1,277 Mcf per day in 2008. Ship Shoal 258/259 was shut in from late August through late October 2008 and South Timbalier 295 was shut in from late August until late December 2008 as a result of downtime for the hurricanes and repairs to third-party pipelines. Hurricanes Gustav and Ike reduced natural gas sales approximately 155 Mcf per day, while natural depletion contributed approximately 88 Mcf per day to the decline in natural gas volumes from 2007.

Crude Oil Sales

2009 vs. 2008 Crude oil sales in 2009 dropped 39 percent from the $3.4 million of oil sales reported in 2008. A $53.01 per barrel, or 48 percent, decline in average realized oil price from 2008 drove the decline in sales. A $1.6 million decline in sales from lower prices was partially offset by $0.3 million of production increases. The Partnership's 2009 crude oil sales volumes increased 17 percent from 2008, rising to 35,742 barrels of oil per day in 2009. The increase in production reflected less downtime at South Timbalier 295 for inclement weather and third-party pipeline repairs.

2008 vs. 2007 Crude oil sales in 2008 totaled $3.4 million, up two percent from the same period in 2007 on higher oil prices. The Partnership's average realized oil price for the year increased 49 percent to a record $110.61 per barrel. The Partnership's realized oil price reached a high of $135.51 per barrel in June 2008 before declining to approximately $40.00 per barrel at the end of December 2008. Crude oil sales volumes in 2008 declined 31 percent from 2007 primarily as a result of South Timbalier 295 being shut in for nearly four months for downtime for Hurricanes Gustav and Ike and damage to a third-party pipeline caused by Hurricane Ike. Oil production from South Timbalier commenced flowing in late December 2008 as repairs were completed to the third-party sales line.

Operating Expenses

2009 vs. 2008 The Partnership's depreciation, depletion and amortization (DD&A) rate, expressed as a percentage of oil and gas sales, was approximately 22 percent during 2009, up from 11 percent in 2008. The increase in rate as a percentage of oil and gas sales was driven by lower oil and gas prices in 2009. DD&A on an absolute basis increased as a result of increased production and higher plugging and dismantlement cost. Lease operating expense (LOE) increased 25 percent over the previous year on higher workover and repair and maintenance costs. During 2009, the Partnership participated in workovers at North Padre Island 969/976, Ship Shoal 258/259 and South Timbalier 295. LOE for the period also included repairs to a compressor on the South Timbalier 295 platform and maintenance cost at Matagorda Island 681/682. LOE for 2009 excludes $64,605 of expected insurance reimbursement for Hurricane Ike damage. The repair cost subject to insurance reimbursement is primarily for a gathering line at Ship Shoal 258/259 and for handrail, grating and decking repairs on various platforms. Gathering and transportation costs increased from 2008 levels reflecting the increase in sales volumes in 2009. Administrative expense for the year decreased slightly from 2008 to $418,000.

2008 vs. 2007 The Partnership's DD&A rate, expressed as a percentage of oil and gas sales, was approximately 11 percent during 2008, down slightly from the 13 percent in 2007. The decline in rate as a percentage of sales reflected favorable reserve revisions booked in the fourth quarter of 2007, lower net amortizable cost and higher oil and gas prices boosting 2008 oil and gas sales. LOE decreased 17 percent from the previous year on lower repair and maintenance costs at North Padre Island 969/976. Accretion on asset retirement obligations increased from $44,522 in 2007 to $63,489 in 2008 with the increase in provision for estimated future plugging cost during late 2007. Gathering and transportation costs decreased 28 percent from 2007 levels reflecting the decrease in sales volumes for the period. Administrative expense for the year increased slightly for the year to $451,154 as a result of legal costs associated with a third-party tender offer described under Part II, Item 5 of this Form 10-K.

The Partnership sells oil and natural gas under two types of transactions, both of which include a transportation charge. One is a netback arrangement, under which the Partnership sells oil or natural gas as the wellhead and collects a price, net of transportation incurred by the purchaser. In this case, the Partnership records sales at the price received from the purchaser which is net of transportation costs. Under the other arrangement, the Partnership sells oil or natural gas at a specific delivery point, pays transportation to a carrier and receives from the purchaser a price with no transportation deduction. In this case, the Partnership records the transportation cost as gathering and transportation costs. The Partnership's treatment of transportation costs is pursuant to Emerging Issues Task Force Issue 00-10, "Accounting or Shipping and Handling Fees and Costs" and as a result a portion of our transporting costs are reflected in sales prices and a portion is reflected as transportation and gathering costs.

Capital Resources and Liquidity

The Partnership's primary capital resource is net cash provided by operating activities, which totaled $2.0 million for 2009. The Partnership's 2009 net cash provided by operating activities decreased $4.4 million, or 69 percent, from a year ago as a result of oil and gas prices dropping 48 percent and 56 percent, respectively, from 2008. A $.3 million increase in lease operating expense in 2009 also contributed to net cash provided by operating activities declining from 2008. Net cash provided by operating activities in 2008 of $6.4 million increased five percent from 2007 on higher oil and gas prices.

At December 31, 2009, the Partnership had approximately $2.0 million in cash and cash equivalents, up from slightly more than $1.3 million at December 31, 2008. The Partnership intends to maintain cash and cash equivalents in the Partnership at least sufficient to cover the discounted value of its future asset retirement obligations (ARO). The Partnership increased its cash balances during 2009 to fund development cost projected to be incurred in the first half of 2010, and as a reserve for the higher projected ARO.

The Partnership's future financial condition, results of operations and cash from operating activities will largely depend upon prices received for its oil and natural gas production. A substantial portion of the Partnership's production is sold under market-sensitive contracts. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond the Partnership's control. These factors include worldwide political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand, and the price and availability of alternative fuels.

The Partnership's oil and gas reserves and production will also significantly impact future results of operations and cash from operating activities. The Partnership's production is subject to fluctuations in response to remaining quantities of oil and gas reserves, weather, pipeline capacity, consumer demand, mechanical performance and workover, recompletion and drilling activities. Declines in oil and gas production can be expected in future years as a result of normal depletion and the Partnership not participating in acquisition or exploration activities. Based on production estimates from independent engineers and current market conditions, the Partnership expects it will be able to meet its liquidity needs for routine operations in the foreseeable future.

Approximately 77 percent of the Partnership's proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe, or that have been completed but not yet produced or zones that have been produced in the past, but are not now producing due to mechanical reasons. These reserves may be regarded as less certain than producing reserves because they are frequently based on volumetric calculations rather than performance data. Future production associated with behind pipe reserves is scheduled to follow depletion of the currently producing zones in the same wellbores. It should be noted that additional capital will have to be spent to access these reserves and that the estimated reserves from these projects are based on prices at December 31, 2009. The Partnership's liquidity may be negatively impacted if the actual quantities of reserves that are ultimately produced are materially different from current estimates. Also, if prices decline significantly from current levels, the Partnership may not be able to fund the necessary capital investment, or development of the remaining reserves may not be economical for the Partnership.

The Partnership may reduce capital expenditures or distributions to partners, or both, as cash from operating activities decline. In the event that future short-term operating cash requirements are greater than the Partnership's financial resources, the Partnership may seek short-term, interest-bearing advances from the Managing Partner as needed. The Managing Partner, however, is not obligated to make loans to the Partnership. The Partnership does not intend to incur debt from banks or other outside sources or solicit capital from exiting Unit holders or in the open market.

On an ongoing basis, the Partnership reviews the possible sale of lower value properties prior to incurring associated dismantlement and abandonment cost. The Partnership did not sell any properties in 2009, 2008 or 2007.

Capital Commitments

The Partnership's primary needs for cash are for operating expenses, drilling and recompletion expenditures, future dismantlement and abandonment costs, distributions to Investing Partners, and the purchase of Units offered by Investing Partners under the right of presentment. The Partnership had no outstanding debt or lease commitments at December 31, 2009. The Partnership did not have any contractual obligations as of December 31, 2009, other than the liability for dismantlement and abandonment costs of its oil and gas properties. The Partnership has recorded a separate liability for the fair value of the ARO as discussed under the discussion of critical accounting policies noted below.

During 2009, the Partnership's oil and gas property expenditures totaled $0.6 million. The Partnership participated in two recompletions in the North Padre Island 969/976 Field during 2009 and one recompletion at Matagorda Island 681/682 during the year. During 2008, the Partnership's oil and gas property expenditures totaled $1.0 million. The Partnership participated in drilling one well in the North Padre Island 969/976 Field during 2009. The well was unsuccessful in its initial evaluation, and Apache and the Partnership elected not to participate in a sidetrack well proposed by the operator. The Partnership also participated in two recompletions in each of its Matagorda Island 681/682 and South Timbalier 295 fields during 2009. The two recompletions at Matagorda Island 681/682 were successful while the recompletions at South Timbalier 295 were unsuccessful. During 2007, the Partnership's oil and gas property expenditures totaled $0.2 million as the Partnership did not participate in any drilling or recompletion projects in 2007.

Based on preliminary information provided by the operators of the properties in which the Partnership owns interests, the Partnership anticipates capital expenditures will total approximately $3 million in 2010 for drilling at Ship Shoal 258/259 and recompletions at South Timbalier 295 and North Padre Island 969/976. Such estimates may change based on realized oil and gas prices, drilling results, rates charged by drilling contractors or changes by the operator to the development plan.

During 2009, no distributions were paid to Investing Partners. Distributions of $5,500 per Unit and $4,000 per Unit were made to Partners during 2008 and 2007, respectively, resulting in total distributions to Limited Partners of $5.7 million in 2008 and $4.2 million in 2007. The amount of future distributions will be dependent on actual and expected production levels, realized and expected oil and gas prices, expected drilling and recompletion expenditures, and prudent cash reserves for future dismantlement and abandonment costs that will be incurred after the Partnership's reserves are depleted.

The Partnership is not likely to make a distribution in the first quarter of 2010 as a result of planned capital outlays for drilling and recompletion activities during 2010. The Partnership intends to maintain cash and cash equivalents in the Partnership at least sufficient to cover the discounted value of its future asset retirement obligations.

In February 1994, an amendment to the Partnership Agreement created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash. In 2009, the Partnership did not offer to purchase any Units from Investing Partners as a result of the limited amount of cash available for discretionary purposes. In 2008 and 2007, Investing Partners were paid $228,995 and $124,512, respectively, for a total of 26.8 Units.

There will be two rights of presentment in 2010, but the Partnership is not in a position to predict how many Units will be presented for repurchase and cannot, at this time, determine if the Partnership will have sufficient funds available to repurchase Units. The Amended Partnership Agreement contains limitations on the number of Units that the Partnership can repurchase, including an annual limit on repurchases of 10 percent of outstanding Units. The Partnership has no obligation to repurchase any Units presented to the extent that it determines that it has insufficient funds for such repurchases. The Partnership is not likely to have funds available to repurchase Units during the first half of 2010.

Off-Balance Sheet Arrangements

The Partnership does not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or any other purpose. Any future transactions involving off-balance sheet arrangements will be fully scrutinized by the Managing Partner and disclosed by the Partnership.

Critical Accounting Policies and Estimates

The Partnership prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States, which requires management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and accompanying notes. Management identifies certain accounting policies as critical based on, among other things, their impact on the Partnership's financial condition, results of operations or liquidity and the degree of difficulty, subjectivity and complexity in their development. The following details the more significant accounting policies, estimates and judgments of the Partnership. Additional accounting policies and estimates made by management are discussed in Note 2 of Item 8 of this Form 10-K.

Reserve Estimates

In January 2009, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting" (Release 33-8995), amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures. In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-03, *"Oil and Gas Reserve Estimation and Disclosures"* (ASU 2010-03), which amends Accounting Standards Codification (ASC) Topic 932, "*Extractive Industries—Oil and Gas"* to align the guidance with the changes made by the SEC. The Partnership adopted Release 33-8995 and the amendments to ASC Topic 932 resulting from ASU 2010-03 (collectively, the Modernization Rules) effective December 31, 2009.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGL's that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations.

Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, the Partnership's reserves have a significant impact on its financial statements. For example, the quantity of reserves could significantly impact the Partnership's DD&A expense. The Partnership's oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. These reserves are the basis for our supplemental oil and gas disclosures.

Reserves as of December 31, 2009 were calculated using an average of commodity prices in effect on the first day of each month in 2009. Reserves as of December 31, 2008 and 2007 were estimated using prices in effect at the end of those years, in accordance with SEC guidance in effect prior to the issuance of the Modernization Rules.

The Partnership has elected not to disclose probable and possible reserves or reserve estimates based upon futures or other prices in this filing.

The Partnership's estimate of proved oil and gas reserves are prepared by Ryder Scott Company, L.P. Petroleum Consultants, independent petroleum engineers, utilizing oil and gas price data and cost estimates provided by Apache as Managing Partner.

Asset Retirement Obligation (ARO)

The Partnership has obligations to remove tangible equipment and restore the land or seabed at the end of oil and gas production operations. These obligations may be significant in light of the Partnership's limited operations and estimate of remaining reserves. The Partnership'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.

Asset retirement obligations associated with retiring tangible long-lived assets, are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable. This liability is offset by a corresponding increase in the carrying amount of the underlying asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity 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, 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.

The Partnership's revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas and NGLs, which have historically been very volatile. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to the Partnership's natural gas production. Prices received for oil and gas production have been and remain volatile and unpredictable. During 2009, monthly oil price realizations ranged from a low of $33.34 per barrel to a high of $74.81 per barrel. Gas price realizations ranged from a monthly low of $2.91 per Mcf to a monthly high of $5.94 per Mcf during the same period. Based on the Partnership's average daily production for 2009, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $36,000 and a $.10 per Mcf change in the weighted average realized price of natural gas would have increased or decreased revenues for the year by approximately $53,000. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2009. Due to the volatility of commodity prices, the Partnership is not in a position to predict future oil and gas prices.

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impact the price we receive for the commodities we produce. In addition, our exploration and development activities and equipment can be adversely affected by severe weather, such as hurricanes in the Gulf of Mexico, 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.

Forward-Looking Statements and Risk

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

- the market prices of oil, natural gas, NGLs and other products or services;
- the supply and demand for oil, natural gas, NGLs and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions;
- the availability of capital resources;

- capital expenditure and other contractual obligations;
- weather conditions;
- inflation rates;
- the availability of goods and services;
- legislative or regulatory changes;
- terrorism;
- the capital markets and related risks such as general credit, liquidity, market and interest-rate risks; and
- other factors disclosed under Items 1 and 2 – “Business and Properties — Estimated Proved Reserves and Future Net Cash Flows,” Item 1A – “Risk Factors,” Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” Item 7A – “Quantitative and Qualitative Disclosures About Market Risk” and elsewhere in this Form 10-K.

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

APACHE OFFSHORE INVESTMENT PARTNERSHIP
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Schedules –

All 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 financial statements or related notes thereto.

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Partnership 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 Partnership 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 Partnership's and Managing Partner'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 appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by the Managing Partner's board of directors, applicable to all the Managing Partner's directors, officers and employees.

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

/s/ G. Steven Farris
G. Steven Farris
Chairman and Chief Executive Officer
(principal executive officer)
of Apache Corporation, Managing Partner

/s/ Roger B. Plank
Roger B. Plank
President (principal financial officer)
of Apache Corporation, Managing Partner

/s/ Rebecca A. Hoyt
Rebecca A. Hoyt
Vice President and Controller
(principal accounting officer)
of Apache Corporation, Managing Partner

Houston, Texas
February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Apache Offshore Investment Partnership:

We have audited the accompanying consolidated balance sheets of Apache Offshore Investment Partnership (a Delaware general partnership) as of December 31, 2009 and 2008, and the related consolidated statements of income, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, in 2009, the Partnership adopted SEC Release 33-8995 and the amendments to ASC Topic 932, "Extractive Industries – Oil and Gas," resulting from ASU 2010-03 (collectively, the Modernization Rules).

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

ERNST & YOUNG LLP

Houston, Texas
February 26, 2010

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED INCOME

	For the Year Ended December 31,		
	2009	2008	2007
REVENUES:			
Oil and gas sales	$4,310,969	$7,927,690	$7,679,104
Interest income	229	46,193	104,274
	4,311,198	7,973,883	7,783,378
OPERATING EXPENSES:			
Depreciation, depletion and amortization	960,632	901,633	998,826
Asset retirement obligation accretion	67,297	63,489	44,522
Lease operating expenses	1,445,122	1,153,688	1,393,734
Gathering and transportation costs	88,064	69,022	96,082
Administrative	418,000	451,154	416,000
	2,979,115	2,638,986	2,949,164
NET INCOME	$1,332,083	$5,334,897	$4,834,214
NET INCOME ALLOCATED TO:			
Managing Partner	$ 446,888	$1,228,783	$1,145,720
Investing Partners	885,195	4,106,114	3,688,494
	$1,332,083	$5,334,897	$4,834,214
NET INCOME PER INVESTING PARTNER UNIT	$ 867	$ 3,976	$ 3,531
WEIGHTED AVERAGE INVESTING PARTNER UNITS OUTSTANDING	1,021.5	1,032.7	1,044.5

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 1,332,083	$ 5,334,897	$ 4,834,214
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	960,632	901,633	998,826
Asset retirement obligation accretion	67,297	63,489	44,522
Dismantlement and abandonment cost	(37,720)	—	—
Changes in operating assets and liabilities:			
(Increase) decrease in accrued receivables	(13,594)	31,441	170,918
Increase (decrease) in accrued operating expense	7,799	(139,712)	150,712
Increase (decrease) in receivable/payable from Apache Corporation	(329,519)	195,645	(123,581)
Net cash provided by operating activities	1,986,978	6,387,393	6,075,611
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas properties	(610,279)	(956,051)	(153,814)
Increase (decrease) in accrued development cost	(22,629)	22,629	—
Net cash used in investing activities	(632,908)	(933,422)	(153,814)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repurchase of Partnership Units	—	(228,995)	(124,512)
Distributions to Investing Partners	—	(5,679,725)	(4,184,610)
Distributions to Managing Partner	(437,273)	(1,195,521)	(1,189,789)
Net cash used in financing activities	(437,273)	(7,104,241)	(5,498,911)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	916,797	(1,650,270)	422,886
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	1,131,615	2,781,885	2,358,999
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2,048,412	$ 1,131,615	$ 2,781,885

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
CONSOLIDATED BALANCE SHEET

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,048,412	$ 1,131,615
Accrued revenues receivable	319,734	330,818
Accrued insurance receivable	24,678	—
Receivable from Apache Corporation	82,902	—
	2,475,726	1,462,433
OIL AND GAS PROPERTIES, on the basis of full cost accounting:		
Proved properties	188,458,320	186,955,531
Less — Accumulated depreciation, depletion and amortization	(182,698,178)	(181,737,546)
	5,760,142	5,217,985
	$ 8,235,868	$ 6,680,418
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accrued operating expense	$ 106,405	$ 98,606
Accrued exploration and development	—	22,629
Payable to Apache Corporation	—	246,617
	106,405	367,852
ASSET RETIREMENT OBLIGATION	2,043,895	1,121,808
COMMITMENTS AND CONTINGENCIES (Note 7)		
PARTNERS' CAPITAL:		
Managing Partner	74,080	64,465
Investing Partners (1,021.5 Units outstanding)	6,011,488	5,126,293
	6,085,568	5,190,758
	$ 8,235,868	$ 6,680,418

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED CHANGES IN PARTNERS' CAPITAL

	Managing Partner	Investing Partners	Total
BALANCE, DECEMBER 31, 2006	$ 75,272	$ 7,549,527	$ 7,624,799
Distributions	(1,189,789)	(4,184,610)	(5,374,399)
Repurchase of Partnership Units	—	(124,512)	(124,512)
Net income	1,145,720	3,688,494	4,834,214
BALANCE, DECEMBER 31, 2007	$ 31,203	$ 6,928,899	$ 6,960,102
Distributions	(1,195,521)	(5,679,725)	(6,875,246)
Repurchase of Partnership Units	—	(228,995)	(228,995)
Net income	1,228,783	4,106,114	5,334,897
BALANCE, DECEMBER 31, 2008	$ 64,465	$ 5,126,293	$ 5,190,758
Distributions	(437,273)	—	(437,273)
Net income	446,888	885,195	1,332,083
BALANCE, DECEMBER 31, 2009	$ 74,080	$ 6,011,488	$ 6,085,568

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION

Nature of Operations

Apache Offshore Investment Partnership, a Delaware general partnership (the Investment Partnership), was formed on October 31, 1983, consisting of Apache Corporation (Apache or Managing Partner) as Managing Partner and public investors (the Investing Partners). The Investment Partnership invested its entire capital in Apache Offshore Petroleum Limited Partnership, a Delaware limited partnership (the Operating Partnership). The primary business of the Investment Partnership is to serve as the sole limited partner of the Operating Partnership. The primary business of the Operating Partnership is to conduct oil and gas exploration, development and production operations. The Operating Partnership conducts the operations of the Investment Partnership. The accompanying financial statements include the accounts of both the Investment Partnership and Operating Partnership. Apache is the general partner of both the Investment and Operating partnerships, and held approximately five percent of the 1,021.5 Investing Partner Units (Units) outstanding at December 31, 2009. The term “Partnership”, as used hereafter, refers to the Investment Partnership or the Operating Partnership, as the case may be.

The Partnership purchased, at cost, an 85 percent interest in offshore leasehold interests acquired by Apache as a co-venturer in a series of oil and gas exploration, development and production activities on 87 federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. The remaining 15 percent interest was purchased by an affiliated partnership or retained by Apache. The Partnership acquired an increased net revenue interest in Matagorda Island Blocks 681 and 682 in November 1992, when the Partnership and Apache formed a joint venture to acquire a 92.6 percent working interest in the blocks.

Since inception, the Partnership has participated in 14 federal offshore lease sales in which 49 prospects were acquired (over the same period, 45 of those prospects have been surrendered/sold). The Partnership’s working interests in the four remaining venture prospects range from 6.29 percent to 7.08 percent. As of December 31, 2009, the Partnership held a remaining interest in nine tracts acquired through federal lease sales.

The Partnership’s future financial condition and results of operations will depend largely upon prices received for its oil and natural gas production and the costs of acquiring, finding, developing and producing reserves. A substantial portion of the Partnership’s production is sold under market-sensitive contracts. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond the Partnership’s control. These factors include worldwide political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand, and the price and availability of alternative fuels.

Under the terms of the Partnership Agreements, the Investing Partners receive 80 percent and Apache receives 20 percent of revenue. Lease operating, gathering and transportation, and administrative expenses are allocated to the Investing Partners and Apache in the same proportion as revenues. The Investing Partners receive 100 percent of the interest income earned on short-term cash investments. The Investing Partners generally pay for 90 percent and Apache generally pays for 10 percent of exploration and development costs and expenses incurred by the Partnership. However, intangible drilling costs, interest costs and fees or expenses related to the loans incurred by the Partnership are allocated 99 percent to the Investing Partners and one percent to Apache until such time as the amount so allocated to the Investing Partners equals 90 percent of the total amount of such costs, including such costs incurred by Apache prior to the formation of the Partnership.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Right of Presentment

In February 1994, an amendment to the Partnership Agreement created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash. In 2009, the Partnership did not offer to purchase any Units from Investing Partners as a result of the limited amount of cash available for discretionary purposes. In 2008 and 2007, Investing Partners were paid $228,995 and $124,512, respectively, for a total of 26.8 Units.

The Partnership is not in a position to predict how many Units will be presented for repurchase during 2010; however, no more than 10 percent of the outstanding Units may be purchased under the right of presentment in any year. The Partnership has no obligation to purchase any Units presented to the extent that it determines that it has insufficient funds for such purchases.

The table below sets forth the total repurchase price and the repurchase price per Unit for all outstanding Units at each presentment period, based on the right of presentment valuation formula defined in the amendment to the Partnership Agreement. The right of presentment offers made twice annually are based on a discounted Unit value formula. The discounted Unit value will be not less than the Investing Partner's share of: (a) the sum of (i) 70 percent of the discounted estimated future net revenues from proved reserves, discounted at a rate of 1.5 percent over prime or First National Bank of Chicago's base rate in effect at the time the calculation is made, (ii) cash on hand, (iii) prepaid expenses, (iv) accounts receivable less a reasonable reserve for doubtful accounts, (v) oil and gas properties other than proved reserves at cost less any amounts attributable to drilling and completion costs incurred by the Partnership and included therein, and (vi) the book value of all other assets of the Partnership, less the debts, obligations and other liabilities of all kinds (including accrued expenses) then allocable to such interest in the Partnership, all determined as of the valuation date, divided by (b) the number of Units, and fractions thereof, outstanding as of the valuation date. The discounted Unit value does not purport to be, and may be substantially different from, the fair market value of a Unit.

Right of Presentment Valuation Date	Total Valuation Price	Valuation Price Per Unit
December 31, 2006	$15,207,303	$12,507
June 30, 2007	13,866,608	11,282
December 31, 2007	15,806,599	13,225
June 30, 2008	17,239,136	13,245
December 31, 2008	9,701,665	9,497
June 30, 2009	8,864,008	8,677

	2009	2008	2007
Investing Partner Units Outstanding:			
Balance, beginning of year	1,021.5	1,038.2	1,048.3
Repurchase of Partnership Units	—	(16.7)	(10.1)
Balance, end of year	1,021.5	1,021.5	1,038.2

Capital Contributions

A total of $85,000 per Unit, or approximately 57 percent, of investor subscription had been called through December 31, 2009. The Partnership determined the full purchase price of $150,000 per Unit was not needed, and upon completion of the last subscription call in November 1989, released the Investing Partners from their remaining liability. As a result of investors defaulting on cash calls and repurchases under the presentment offer discussed above, the original 1,500 Units have been reduced to 1,021.5 Units at December 31, 2009.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by the Partnership reflect industry practices and conform to accounting principles generally accepted in the United States (GAAP). Significant policies are discussed below.

Statement Presentation

The accompanying consolidated financial statements include the accounts of Apache Offshore Investment Partnership and Apache Offshore Petroleum Limited Partnership after elimination of intercompany balances and transactions.

Cash Equivalents

The Partnership considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Oil and Gas Properties

The Partnership uses the full cost method of accounting for its investment in oil and gas properties for financial statement purposes. Under this method of accounting, the Partnership capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves. The amounts capitalized under this method include dry hole costs, leasehold costs, engineering, geological, exploration, development and other similar costs. Costs associated with production and administrative functions are expensed in the period incurred. The Partnership includes the present value of its dismantlement, restoration and abandonment costs within the capitalized oil and gas property balance as described in Note 8. Unless a significant portion of the Partnership's reserve volumes are sold (greater than 25 percent), proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs, and gains or losses are not recognized.

Capitalized costs of oil and gas properties are amortized on the future gross revenue method whereby depreciation, depletion and amortization (DD&A) expense is computed quarterly by dividing current period oil and gas sales by estimated future gross revenue from proved oil and gas reserves (including current period oil and gas sales) and applying the resulting rate to the net cost of evaluated oil and gas properties, including estimated future development costs.

Under the full-cost method of accounting, the Partnership limits the capitalized costs of proved oil and gas properties, net of accumulated DD&A, to the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, if any. This ceiling test is performed each quarter. If capitalized costs exceed this limit, the excess is charged to DD&A expense. The Partnership has not recorded any write-downs of capitalized costs for the three years presented. Please see "Future Net Cash Flows" in the Supplemental Oil and Gas Disclosures included in this Form 10-K for a discussion on calculation of estimated future net cash flows.

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

The estimate of future net cash flows as of December 31, 2009, is calculated using a discount rate of 10 percent per annum, end-of-period costs, and an unweighted arithmetic average commodity prices in effect on the first day of each month in 2009, held flat for the life of production, except where prices are defined by contractual arrangements. Prior to adoption of the Modernization Rules, effective in the fourth quarter of 2009, estimated future net cash flows were calculated using commodity prices in effect at the end of each quarter. If capitalized costs exceed this ceiling, the excess is charged to expense and reflected as additional DD&A. See Supplemental Oil and Gas Disclosures for a discussion on calculation of estimated future net cash flows.

Asset Retirement Obligation

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

Revenue Recognition

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 collectability of the revenue is probable. The Partnership uses the sales method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas sold to purchasers. The volumes of gas sold may differ from the volumes to which the Partnership is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the underproduced owner to recoup its entitled share through production. As of December 31, 2009 and 2008, the Partnership did not have any liabilities for imbalances in excess of remaining reserves. No receivables are recorded for those wells where the Partnership has taken less than its share of production. Gas imbalances are reflected as adjustments to proved gas revenues and future cash flows in the unaudited supplemental oil and gas disclosures. Adjustments for gas imbalances totaled less than one percent of the Partnership’s proved gas reserves at December 31, 2009, 2008 and 2007.

Insurance Coverage

The Partnership 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.

Net Income Per Investing Unit

The net income per Investing Partner Unit is calculated by dividing the aggregate Investing Partners’ net income for the period by the number of weighted average Investing Partner Units outstanding for that period.

Income Taxes

The profit or loss of the Partnership for federal income tax reporting purposes is included in the income tax returns of the partners. Accordingly, no recognition has been given to income taxes in the accompanying financial statements.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the 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. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Partnership bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. 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 reserve quantities and the related present value of estimated future net cash flows therefrom. (See the unaudited "Supplemental Oil and Gas Disclosures" below), asset retirement obligations and contingency obligations.

Receivable from / Payable to Apache Corporation

The receivable from/payable to Apache Corporation, the Partnership's Managing Partner (Apache or the Managing Partner), represents the net result of the Investing Partners' revenue and expenditure transactions in the current month. Generally, cash in this amount will be paid by Apache to the Partnership or transferred to Apache in the month after the Partnership's transactions are processed and the net results of operations are determined.

Maintenance and Repairs

Maintenance and repairs are charged to expense as incurred.

Shipping and Handling Costs

To comply with the consensus reached on Emerging Issues Task Force Issue 00-10, "Accounting for Shipping and Handling Fees and Costs", third party gathering and transportation costs have been reported as an operating cost instead of a reduction of revenues.

Recently Issued Accounting Standards Not Yet Adopted

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

(3) COMPENSATION TO APACHE

Apache is entitled to the following types of compensation and reimbursement for costs and expenses.

	Total Reimbursed by the Investing Partners for the Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
a. Apache is reimbursed for general, administrative and overhead expenses incurred in connection with the management and operation of the Partnership's business	$ 334	$ 361	$ 333
b. Apache is reimbursed for development overhead costs incurred in the Partnership's operations. These costs are based on development activities and are capitalized to oil and gas properties	$ 30	$ 26	$ 7

Apache operates certain Partnership properties. Billings to the Partnership are made on the same basis as to unaffiliated third parties or at prevailing industry rates.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(4) OIL AND GAS PROPERTIES

The following tables contain direct cost information and changes in the Partnership's oil and gas properties for each of the years ended December 31. All costs of oil and gas properties are currently being amortized.

	2009	2008 (In thousands)	2007
Oil and Gas Properties			
Balance, beginning of year	$ 186,955	$ 185,999	$ 185,574
Costs incurred during the year:			
Development —			
Investing Partners	1,407	939	319
Managing Partner	96	17	106
Balance, end of year	$ 188,458	$ 186,955	$ 185,999

Development cost for 2009 includes $.9 million of asset retirement cost.

	Managing Partner	Investing Partners (In thousands)	Total
Accumulated Depreciation, Depletion and Amortization			
Balance, December 31, 2006	$ 20,893	$ 158,944	$ 179,837
Provision	4	995	999
Balance, December 31, 2007	$ 20,897	$ 159,939	$ 180,836
Provision	16	886	902
Balance, December 31, 2008	$ 20,913	$ 160,825	$ 181,738
Provision	18	942	960
Balance, December 31, 2009	$ 20,931	$ 161,767	$ 182,698

The Partnership's aggregate DD&A expense as a percentage of oil and gas sales for 2009, 2008 and 2007 was 22 percent, 11 percent and 13 percent, respectively.

(5) MAJOR CUSTOMER AND RELATED PARTIES INFORMATION

Revenues received from major third party customers that exceeded ten percent of oil and gas sales are discussed below. No other third party customers individually accounted for more than ten percent of oil and gas sales.

In 2009, sales to Shell Trading Company accounted for 48 percent of the Partnership's oil and gas sales. Sales to Shell Trading Company and Plains Marketing LP accounted for 27 percent and 16 percent, respectively, of the Partnership's oil and gas sales in 2008. Sales to Shell Trading Company accounted for 35 percent of the Partnership's oil and gas sales in 2007.

Effective November 1992, with Apache's and the Partnership's acquisition of an additional net revenue interest in Matagorda Island Blocks 681 and 682, a wholly-owned subsidiary of Apache purchased from Shell Oil Company (Shell) a 14.4 mile natural gas and condensate pipeline connecting Matagorda Island Block 681 to onshore markets. The Partnership paid the Apache subsidiary transportation fees of $24,210 in 2009. The partnership paid the Apache subsidiary transportation fees totaling $19,124 in 2008 and $4,248 in 2007 for the Partnership's share of gas. The fees were at the same rates and terms as previously paid to Shell.

All transactions with related parties were consummated at fair value.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Partnership's revenues are derived principally from uncollateralized sales to customers in the oil and gas industry; therefore, customers may be similarly affected by changes in economic and other conditions within the industry. The Partnership has not experienced material credit losses on such sales.

(6) FINANCIAL INSTRUMENTS

The carrying amount of cash and cash equivalents, accrued revenues receivables and accrued costs included in the accompanying balance sheet approximated their fair values at December 31, 2009 and 2008 due to their short maturities. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2009.

(7) COMMITMENTS AND CONTINGENCIES

Litigation — The Partnership is subject to governmental and regulatory controls arising in the ordinary course of business. It is the opinion of the Apache's management that all claims and litigation involving the Partnership are not likely to have a material adverse effect on its financial position or results of operations.

Environmental — The Partnership, as an owner or lessee of interests in oil and gas properties, is subject to various federal, 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 and subject the lessee to liability for pollution damages. Apache maintains insurance coverage on the Partnership's properties, which it believes, is customary in the industry, although it is not fully insured against all environmental risks.

(8) ASSET RETIREMENT OBLIGATION

The following table is a reconciliation of the Partnership's ARO liability for the years ended December 31, 2009 and 2008:

	2009	2008
Asset retirement obligation at beginning of period	$ 1,121,808	$ 1,058,319
Accretion expense	67,297	63,489
Liabilities settled	(37,720)	—
Revisions in estimated liabilities	892,510	—
Asset retirement obligation at December 31	$ 2,043,895	$ 1,121,808

The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Partnership's oil and gas properties. The Partnership utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Partnership estimates the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. 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.

Liabilities settled primarily relate to individual wells plugged and abandoned during the period. Revisions to estimated liabilities in 2009 reflected the Managing Partner's updated estimates of the extent of the work required and cost involved in the dismantlement and site reclamation of offshore properties, and shorter reserve lives projected for certain of the Partnership's properties.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(9) TAX-BASIS FINANCIAL INFORMATION

A reconciliation of ordinary income for federal income tax reporting purposes to net income under accounting principles generally accepted in the United States is as follows:

	2009	2008	2007
Net partnership ordinary income for federal income tax reporting purposes	$ 1,464,728	$ 5,184,702	$ 5,475,029
Plus: Items of current expense for tax reporting purposes only —			
Intangible drilling cost	579,318	851,644	35,699
Dismantlement and abandonment cost	37,720	—	—
Tax depreciation	278,246	263,673	366,834
	895,284	1,115,317	402,533
Less: full cost DD&A expense	(960,632)	(901,633)	(998,826)
Less: asset retirement obligation accretion	(67,297)	(63,489)	(44,522)
Net income	$ 1,332,083	$ 5,334,897	$ 4,834,214

The Partnership's tax bases in net oil and gas properties at December 31, 2009 and 2008 was $3,950,153 and $3,160,711, respectively, lower than carrying value of oil and gas properties under full cost accounting. The difference reflects the timing deductions for depreciation, depletion and amortization, intangible drilling costs and dismantlement and abandonment costs. For federal income tax reporting, the Partnership had capitalized syndication cost of $8,660,878 at December 31, 2009 and 2008.

A reconciliation of liabilities for federal income tax reporting purposes to liabilities under accounting principles generally accepted in the United States is as follows:

	December 31, 2009	December 31, 2008
Liabilities for federal income tax purposes	$ 106,405	$ 367,852
Asset retirement liability	2,043,895	1,121,808
Liabilities under accounting principles generally accepted in the United States	$ 2,150,300	$ 1,489,660

Asset retirement liabilities for future dismantlement and abandonment costs are not recognized for federal income tax reporting purposes until settled.

(10) SUBSEQUENT EVENTS

Subsequent events have been evaluated for recognition and disclosure through February 26, 2010, the date these financial statements were filed with the SEC. No significant subsequent events have been identified.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

Oil and Gas Reserve Information

In January 2009, the SEC issued Release No. 33-8995 amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K and bringing full-cost accounting rules into alignment with the revised disclosure requirements. The new rules include changes to the pricing used to estimate reserves, the option to disclose probable and possible reserves, revised definitions for proved reserves, additional disclosures with respect to undeveloped reserves, and other new or revised definitions and disclosures. In January 2010, the FASB issued ASU No. 2010-03 which amends ASC Topic 932 to align the guidance with the changes made by the SEC. The Partnership adopted these Modernization Rules effective December 31, 2009, and the impact of the adoption did not have a material impact on its results of operations.

The new rules require the use of a 12-month average price, instead of a single-day period end price, to calculate reserves. Application of these rules resulted in the use of lower prices at December 31, 2009, for both oil and gas than would have resulted under the previous rules. Using these lower commodity prices reduced the Partnership’s reported discounted future net cash flows.

The Partnership’s estimate of proved oil and gas reserves are prepared by Ryder Scott Company, L.P. Petroleum Consultants utilizing oil and gas price data and cost estimates provided by Apache as Managing Partner. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. A copy of Ryder Scott’s report on the Shell Offshore Venture, of which the partnership owns approximately 85 percent, is filed as an exhibit to this Form 10-K.

The primarily technical person responsible for overseeing the preparation of the Partnership’s reserve estimates is Mr. Michael F. Stell, a Managing Senior Vice President with Ryder Scott. Mr. Stell has almost 30 years of industry experience and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

At least annually, each property is reviewed in detail by Apache’s centralized and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends and development timing are reasonable. Apache’s engineers furnish this information and estimates of dismantlement and abandonment cost to Ryder Scott for their consideration in preparing the Partnership’s reserve reports. The internal property reviews and collection of data provided to Ryder Scott is overseen by Apache’s Executive Vice President of Corporate Reservoir Engineering.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact.

(Oil in Mbbls and gas in MMcf)

	2009		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Reserves						
Beginning of year	492	2,422	571	3,004	605	3,433
Extensions, discoveries and other additions	—	—	—	—	—	—
Revisions of previous estimates	105	536	(42)	(114)	20	126
Production	(42)	(531)	(37)	(468)	(54)	(555)
End of year	555	2,427	492	2,422	571	3,004
Proved Developed						
Beginning of year	492	2,317	571	2,899	605	3,328
End of year	555	2,322	492	2,317	571	2,899

Oil includes crude oil, condensate and natural gas liquids.

All the Partnership’s reserves are located on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(UNAUDITED)

As of December 31, 2009, the Partnership had one undrilled location classified as proved undeveloped. The location is in North Padre Island 969/976 and is scheduled to be drilled within the next five years. The Partnership carried proved undeveloped reserves of 0.1 Bcf at both December 31, 2009 and 2008.

Approximately 77 percent of the Partnership's proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe, or that have been completed but not yet produced or zones that have been produced in the past, but are not now producing due to mechanical reasons. These reserves may be regarded as less certain than producing reserves because they are frequently based on volumetric calculations rather than performance data. Future production associated with behind pipe reserves is scheduled to follow depletion of the currently producing zones in the same wellbores. It should be noted that additional capital will have to be spent to access these reserves. The capital and economic impact of production timing are reflected in the Partnership's standardized measure under Future Net Cash Flows.

Future Net Cash Flows

Future cash inflows as of December 31, 2009 were calculated using an average of oil and gas prices in effect on the first day of each month in 2009, except where prices are defined by contractual arrangements. Future cash inflows as of December 31, 2008 and 2007 were estimated using oil and gas prices in effect at the end of those years, except where prices are defined by contractual arrangements, in accordance with SEC guidance in effect prior to the issuance of the Modernization Rules. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation.

The following table sets forth unaudited information concerning future net cash flows from proved oil and gas reserves. As the Partnership pays no income taxes, estimated future income tax expenses are omitted. This information does not purport to present the fair value of the Partnership's oil and gas assets, but does present a standardized disclosure concerning possible future net cash flows that would result under the assumptions used.

Discounted Future Net Cash Flows Relating to Proved Reserves

	December 31,		
	2009	2008	2007
		(In thousands)	
Future cash inflows	$ 40,838	$ 36,059	$ 70,569
Future production costs	(7,499)	(7,580)	(8,710)
Future development costs	(6,026)	(4,136)	(4,421)
Net cash flows	27,313	24,343	57,438
10 percent annual discount rate	(12,760)	(8,312)	(25,539)
Discounted future net cash flows	$ 14,553	$ 16,031	$ 31,899

The following table sets forth the principal sources of change in the discounted future net cash flows:

	For the Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Sales, net of production costs	$ (2,778)	$ (6,705)	$ (6,189)
Net change in prices and production costs	797	(13,629)	10,719
Revisions of quantities	4,439	(1,083)	1,469
Accretion of discount	1,603	3,190	2,777
Changes in future development costs	(843)	285	(453)
Changes in production rates and other	(4,696)	2,074	(4,189)
	$ (1,478)	$ (15,868)	$ 4,134

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL QUARTERLY FINANCIAL DATA
(UNAUDITED)

	First	Second	Third	Fourth	Total
	(In thousands, except per Unit amounts)				
2009					
Revenues	$ 1,131	$ 759	$ 1,074	$ 1,347	$ 4,311
Expenses	832	696	716	735	2,979
Net income	$ 299	$ 63	$ 358	$ 612	$ 1,332
Net income allocated to:					
Managing Partner	$ 116	$ 48	$ 111	$ 172	$ 447
Investing Partners	183	15	247	440	885
	$ 299	$ 63	$ 358	$ 612	$ 1,332
Net income per Investing Partner Unit (1)	$ 180	$ 15	$ 242	$ 430	$ 867
2008					
Revenues	$ 2,210	$ 2,610	$ 2,042	$ 1,112	$ 7,974
Expenses	602	634	739	664	2,639
Net income	$ 1,608	$ 1,976	$ 1,303	$ 448	$ 5,335
Net income allocated to:					
Managing Partner	$ 361	$ 438	$ 297	$ 133	$ 1,229
Investing Partners	1,247	1,538	1,006	315	4,106
	$ 1,608	$ 1,976	$ 1,303	$ 448	$ 5,335
Net income per Investing Partner Unit (1)	$ 1,201	$ 1,485	$ 977	$ 306	$ 3,976

(1) The sum of the individual net income per Investing Partner Unit may not agree with the year-to-date net income per Investing Partner Unit as each quarterly computation is based on the weighted average number of Investing Partner Units during that period.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Control and Procedures

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

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 the Report of Management on Internal Control over Financial Reporting, included on page 20 of this report. This annual report does not include an attestation report of the Partnership's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Partnership's registered public accounting firm pursuant to temporary rules of the SEC that permit the Partnership to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

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

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE PARTNERSHIP

All management functions are performed by Apache, the Managing Partner of the Partnership. The Partnership itself has no officers or directors. Information concerning the officers and directors of Apache 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 2010 annual meeting of stockholders of Apache (the Apache Proxy) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, Apache was required to adopt a code of business conduct and ethics for its directors, officers and employees. In February 2004, Apache's Board of Directors adopted a 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 Apache's Code of Conduct under "Governance" on the "About Apache" page of the Apache's website at apachecorp.com. Changes in and any waivers to the Code of Conduct for Apache's directors, chief executive officer and certain senior financial officers will be posted on Apache's website within five business days and maintained for at least twelve months.

ITEM 11. EXECUTIVE COMPENSATION

See Note (3), "Compensation to Apache" of the Partnership's financial statements, under Item 8 above, for information regarding compensation to Apache as Managing Partner. The information concerning the compensation paid by Apache to its officers and directors set forth under the captions "Compensation Discussion and Analysis," "Summary Compensation Table," "Grants of Plan Based Awards," "Outstanding Equity Awards at Fiscal Year-End," "Option Exercises and Stock Vested," "Non-Qualified Deferred Compensation," "Employment Contracts and Termination of Employment and Change-in-Control Arrangements," and "Director Compensation" in the Apache Proxy is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Apache, as an Investing Partner and the General Partner, owns 53 Units, or 5.2 percent of the outstanding Units of the Partnership, as of December 31, 2009. Directors and officers of Apache own four Units, less than one percent of the Partnership's Units, as of December 31, 2009. Apache owns a one-percent General Partner interest (15 equivalent Units). To the knowledge of the Partnership, no Investing Partner owns, of record or beneficially, more than five percent of the Partnership's outstanding Units, except for Apache which owns 53 Units or 5.2 percent of the outstanding Units. Apache did not acquire additional Units during the three years covered by these financial statements. Apache's ownership percentage exceeds five percent due to the decrease in the number of outstanding units resulting from the right of presentment (see Note 1).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

See Note (3), "Compensation to Apache" of the Partnership's financial statements, under Item 8 above, for information regarding compensation to Apache as Managing Partner. See Note (5), "Major Customers and Related Parties Information" of the Partnership's financial statements for amounts paid to subsidiaries of Apache, and for other related party information.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Accountant fees and services paid to Ernst & Young LLP, the Partnership's independent auditors, are included in amounts paid by the Partnership's Managing Partner. Information on the Managing Partner's principal accountant fees and services is set forth under the caption "Independent Public Accountants" in the Apache Proxy.

PART IV

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

a. (1) Financial Statements — See accompanying index to financial statements in Item 8 above.

(2) Financial Statement Schedules — See accompanying index to financial statements in Item 8 above.

(3) Exhibits

3.1	Partnership Agreement of Apache Offshore Investment Partnership (incorporated by reference to Exhibit (3)(i) to Form 10 filed by Partnership with the Commission on April 30, 1985, Commission File No. 0-13546).
3.2	Amendment No. 1, dated February 11, 1994, to the Partnership Agreement of Apache Offshore Investment Partnership (incorporated by reference to Exhibit 3.3 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 0-13546).
3.3	Limited Partnership Agreement of Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit (3)(ii) to Form 10 filed by Partnership with the Commission on April 30, 1985, Commission File No. 0-13546).
10.1	Form of Assignment and Assumption Agreement between Apache Corporation and Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit 10.2 to Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 1992, Commission File No. 0-13546).
10.2	Joint Venture Agreement, dated as of November 23, 1992, between Apache Corporation and Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit 10.6 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-13546).
10.3	Matagorda Island 681 Field Purchase and Sale Agreement with Option to Exchange, dated November 24, 1992, between Apache Corporation, Shell Offshore, Inc. and SOI Royalties, Inc. (incorporated by reference to Exhibit 10.7 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-13546).
*23.1	Consent of Ryder Scott Company, L.P., Petroleum Consultants.
*31.1	Certification of Principal Executive Officer.
*31.2	Certification of Principal Financial Officer.
*32.1	Certification of Principal Executive Officer and Principal Financial Officer.
*99.1	Report of Ryder Scott Company, L.P., Petroleum Consultants.
99.2	Consent statement of the Partnership, dated January 7, 1994 (incorporated by reference to Exhibit 99.1 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 0-13546).
99.3	Proxy statement to be dated on or about March 31, 2010, relating to the 2010 annual meeting of stockholders of Apache Corporation (incorporated by reference to the document filed by Apache pursuant to Rule 14A, Commission File No. 1-4300).

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* Filed herewith.

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, thereunto duly authorized.

APACHE OFFSHORE INVESTMENT PARTNERSHIP

By: Apache Corporation, Managing Partner

Date: February 26, 2010

By: /s/ G. Steven Farris
G. Steven Farris
Chairman of the Board and Chief Executive Officer

POWER OF ATTORNEY

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

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

Name	Title	Date
/s/ G. Steven Farris G. Steven Farris	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 26, 2010
/s/ Roger B. Plank Roger B. Plank	President (principal financial officer)	February 26, 2010
/s/ Rebecca A. Hoyt Rebecca A. Hoyt	Vice President and Controller (principal accounting officer)	February 26, 2010

Name	Title	Date
/s/ Frederick M. Bohen Frederick M. Bohen	Director	February 26, 2010
/s/ Randolph M. Ferlic Randolph M. Ferlic	Director	February 26, 2010
/s/ Eugene C. Fiedorek Eugene C. Fiedorek	Director	February 26, 2010
/s/ A. D. Frazier, Jr. A. D. Frazier, Jr.	Director	February 26, 2010
/s/ Patricia Albjerg Graham Patricia Albjerg Graham	Director	February 26, 2010
/s/ John A. Kocur John A. Kocur	Director	February 26, 2010
/s/ George D. Lawrence George D. Lawrence	Director	February 26, 2010
/s/ F. H. Merelli F. H. Merelli	Director	February 26, 2010
/s/ Rodman D. Patton Rodman D. Patton	Director	February 26, 2010
/s/ Charles J. Pitman Charles J. Pitman	Director	February 26, 2010

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218
FAX (713) 651-0849
TELEPHONE (713) 651-9191

Consent of Ryder Scott Company, L.P.

As independent petroleum engineers, we hereby consent to the incorporation by reference in this Form 10-K of Apache Offshore Investment Partnership to our Firm's name and our Firm's review of the proved oil and gas reserve quantities of Apache Offshore Investment Partnership as of December 31, 2009, and to the inclusion of our report, dated February 5, 2010, as an exhibit to this Form 10-K filed with the Securities and Exchange Commission.

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 24, 2010

EXHIBIT 31.1

CERTIFICATIONS

I, G. Steven Farris, certify that:

1. I have reviewed this annual report on Form 10-K of Apache Offshore Investment Partnership;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information ; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ G. Steven Farris

G. Steven Farris
Chairman of the Board and
Chief Executive Officer (principal executive officer)
of Apache Corporation, Managing Partner

Date: February 26, 2010

EXHIBIT 31.2

CERTIFICATIONS

I, Roger B. Plank, certify that:

1. I have reviewed this annual report on Form 10-K of Apache Offshore Investment Partnership;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Roger B. Plank

Roger B. Plank
President (principal financial officer)
of Apache Corporation, Managing Partner

Date: February 26, 2010

Exhibit 32.1

APACHE OFFSHORE INVESTMENT PARTNERSHIP

**Certification of Chief Executive Officer
and Principal Financial Officer**

I, G. Steven Farris, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the annual report on Form 10-K of Apache Offshore Investment Partnership for the period ended December 31, 2009, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Offshore Investment Partnership.

/s/ G. Steven Farris
By: G. Steven Farris
Title: Chairman of the Board and
Chief Executive Officer (principal executive officer)
of Apache Corporation, Managing Partner

Date: February 26, 2010

I, Roger B. Plank, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the annual report on Form 10-K of Apache Offshore Investment Partnership for the period ended December 31, 2009, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Offshore Investment Partnership.

/s/ Roger B. Plank
By: Roger B. Plank
Title: President (principal financial officer)
of Apache Corporation, Managing Partner

Date: February 26, 2010

Exhibit 99.1

Apache Corporation

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

In the

Shell Offshore Venture

SEC Parameters

As of

December 31, 2009

/s/ Jennifer A. Fitzgerald	/s/ Michael F. Stell
Jennifer A. Fitzgerald, P.E.	Michael F. Stell, P.E.
TBPE License No. 100572	TBPE License No. 56416
Senior Petroleum Engineer	Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

[Seal] [Seal]

February 5, 2010

Apache Corporation
2000 Post Oak Boulevard, Suite 100
Houston, Texas 77056-4400

Gentlemen:

At your request, we have prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests in the Shell Offshore Venture as of December 31, 2009. The subject properties are located in the federal waters offshore Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The results of our third party study, completed on February 1, 2010, are presented herein. The properties reviewed by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Shell Offshore Venture for Apache Corporation (Apache).

The estimated reserves and future net income amounts presented in this report, as of December 31, 2009 are related to hydrocarbon prices. Apache furnished the hydrocarbon prices used in the preparation of this report, which are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Apache Corporation
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests in the
Shell Offshore Venture

	As of December 31, 2009			
	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate — Barrels	108,792	449,269	14	558,075
Plant Products — Barrels	14,367	80,416	0	94,783
Gas — MMCF	832	1,866	123	2,821
Income Data				
Future Gross Revenue	$10,247,622	$ 37,183,453	$ 492,491	$47,923,566
Deductions	6,319,463	9,117,946	474,005	15,911,414
Future Net Income (FNI)	$ 3,928,159	$ 28,065,507	$ 18,486	$32,012,152
Discounted FNI @ 10%	$ 5,172,756	$ 11,837,952	-$2,579	$17,008,129

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an "as-sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of 60° Fahrenheit and 14.73 psia.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Apache. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, transportations costs (shown as other), and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 77 percent of the total future gross revenue from proved reserves and gas reserves account for the remaining 23 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of December 31, 2009
Discount Rate Percent	Total Proved
5	$22,548,809
15	$13,584,496
20	$11,342,199
25	$ 9,790,525

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10 (a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined in the attachment to this report entitled “Petroleum Reserves Definitions.” The developed proved non-producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The gas volumes included herein do not attribute gas consumed in operations as reserves.

While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may also increase or decrease from existing levels, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The reserves included herein were estimated using deterministic methods and presented as incremental quantities.

The reserves and income quantities attributable to the different reserve classifications that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Apache owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The reserves for the properties included herein were estimated by performance methods or the volumetric method. In general, reserves attributable to producing wells were estimated by performance methods such as decline curve analysis and material balance, which utilized extrapolations of historical production and pressure data available through November, 2009 in those cases where such data were considered to be definitive. In certain cases, producing reserves were estimated by the volumetric method where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. Reserves attributable to proved non-producing and undeveloped reserves included herein were estimated by the volumetric method which utilized all pertinent well and seismic data available through December, 2009.

To estimate economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined as of the effective date of the report. Apache has informed us that they have furnished us all of the accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future production and income, we have relied upon data furnished by Apache with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by Apache.

Future Production Rates

Our forecasts of future production rates are based on historical performance from wells now on production. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Apache.

The future production rates from wells now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates.

Hydrocarbon Prices

As previously stated, the hydrocarbon prices furnished by Apache and used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described. Product prices which were actually used for each property reflect adjustment for gravity, quality, local conditions, and/or distance from market.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Apache and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. When applicable for operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Apache and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by Apache were accepted without independent verification.

Because of the direct relationship between volumes of proved undeveloped reserves and development plans, we include in the proved undeveloped category only reserves assigned to undeveloped locations that we have been assured will definitely be drilled. Apache has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

Current costs used by Apache were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Apache. Neither we nor any of our employees have any interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The professional qualifications of the undersigned, the technical person primarily responsible for reviewing and approving the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

This report was prepared for the exclusive use and sole benefit of Apache Corporation and may not be put to other use without our prior written consent for such use. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Jennifer A. Fitzgerald
Jennifer A. Fitzgerald, P.E.
TBPE License No. 100572
Senior Petroluem Engineer

/s/ Michael F. Stell
Michael F. Stell, P.E.
TBPE License No. 56416
Managing Senior Vice President

JAF/sm

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Michael F. Stell was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Mr. Stell, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1992, is a Managing Senior Vice President and also serves as an Engineering Group Leader responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Stell served in a number of engineering positions with Shell Oil Company and Landmark Concurrent Solutions. For more information regarding Mr. Stell's geographic and job specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Experience/Employees.php.

Mr. Stell earned a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Stell fulfills. As part of his 2009 continuing education hours, Mr. Stell attended an internally presented 13 hours of formalized training as well as a day-long public forum relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Stell attended an additional 15 hours of formalized in-house training as well as an additional five hours of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and almost 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Stell has attained the professional qualifications for a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission ("the Commission") published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC Regulations". The SEC Regulations take effect with all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10 (a) for the complete definitions, as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the original document (direct passages excerpted from the aforementioned SEC document are denoted in italics herein).

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward under defined conditions. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC Regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the Commission. The SEC Regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the Commission unless such information is required to be disclosed in the document by foreign or state law as noted in §229.102 (5).

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) *Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:*

(A) *Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*

(B) *The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) *Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.*

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RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs.

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.