

**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, 2017

OR

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

Commission File Number: 0-13546

APACHE OFFSHORE INVESTMENT PARTNERSHIP

Delaware
(State or other jurisdiction of
incorporation or organization)

41-1464066
(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 No

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

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

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 No

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

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

Large accelerated filer	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input checked="" type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2017 \$ 8,516,314

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Apache Corporation's proxy statement relating to its 2018 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 (NGLs) 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 (Mcf/d), 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 Apache Offshore Investment Partnership's working interest therein. Unless otherwise specified, all references to wells and acres are gross.

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, 2017, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as “may,” “will,” “could,” “expect,” “intend,” “project,” “estimate,” “anticipate,” “plan,” “believe,” or “continue” or similar terminology. 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;
- pipeline and gathering system capacity and availability;
- 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, including environmental regulation;
- terrorism or cyber-attacks;
- the capital markets and related risks such as general credit, liquidity, market, and interest-rate risks; and
- other factors disclosed under Item 1A – “Risk Factors,” Item 2 – “Properties — Estimated Proved Reserves and Future Net Cash Flows,” 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.

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 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: Investor Relations, or by telephone at 1-281-302-2286. 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, 2017, 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 development and production activities on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. Except for an additional interest acquired in Matagorda Island Block 681 and 682 in 1992, 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 Venture acquired substantially all of its oil and gas properties through bidding for leases offered by the federal government, and relied on Shell's knowledge and expertise in determining bidding strategies and development of the properties. The Partnership owns working interests ranging from 6.29 percent to 7.08 percent in the Venture's properties.

Apache, as Managing Partner, manages the Partnership's business activities. 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.

2017 Results and Business Development

The Partnership reported a net loss in 2017 of \$0.3 million, or \$246 per Investing Partner Unit. Losses were down approximately \$2.9 million from the \$3.1 million of net loss reported in 2016. The 2016 net loss included \$2.9 million of non-cash write-downs in the carrying value of the Partnership's oil and gas properties. The Partnership's average realized gas price increased 40 percent from a year ago to \$3.49 per Mcf while oil prices increased 19 percent from a year ago to \$48.00 per barrel. Natural gas production averaged 114 Mcf per day in 2017, down 61 percent from 2016. Oil production averaged 46 barrels of oil per day in 2017, down 32 percent from 2016. Production from Ship Shoal 258/259 was shut-in for the majority of 2017 as a result of third-party pipeline maintenance, which is now complete. The operator plans to bring the field back on-line in the first quarter of 2018. South Timbalier 295 also experienced significant production interruptions during the middle of the year as a result of pipeline downtime. During 2017, the Partnership's cash outlays for oil and gas property additions totaled \$36,115 as the Partnership participated in recompletion projects at South Timbalier 295. The Partnership did not participate in any new drilling projects during the year.

Based on preliminary information available to the Partnership, it anticipates capital expenditures will total less than \$200,000 in 2018 for pipeline and recompletion projects scheduled at South Timbalier 295. Additionally, \$540,000 is estimated to be spent in 2018 to abandon several wells currently shut-in at Ship Shoal 258/259 and to remove platforms at North Padre Island 969/976. The abandonment activity at North Padre Island 969/976 was originally scheduled to commence in 2016, but has been deferred to the middle of 2018 and possibly 2019 pending approval from regulators. Such estimates may change based on realized oil and gas prices, drilling and recompletion results, rates charged by contractors or changes by the operator to their development or abandonment plans.

Since inception, the Partnership has acquired an interest in 49 prospects. As of December 31, 2017, 47 of those prospects have been surrendered or sold. As of December 31, 2017, the Partnership had 23 productive wells on the Partnership's two remaining developed fields, both offshore Louisiana. The Partnership had, at December 31, 2017, estimated proved oil and gas reserves of 599,686 barrels of oil equivalent.

For a more in-depth discussion of the Partnership's 2017 results and its capital resources and liquidity, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Marketing

The Partnership has historically marketed its oil and gas production under the joint operating agreements with the operators of its properties. Beginning in 2016, Apache, as Managing Partner of the Partnership, began marketing the Partnership's share of oil production from South Timbalier 295, the Partnership's largest source of production. The third-party operator continues to market all other production of the Partnership. The operator 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. These contracts provide for sales that are priced at prevailing market prices. Apache primarily markets to major oil companies, marketing and transportation companies, and refiners at current index prices, adjusted for quality, transportation, and market-reflective differentials. The change to Apache to market oil production from South Timbalier 295 was made to improve the timing of cash receipts and reduce the credit risk from third-party purchasers and remitters.

Through the operator, the Partnership's natural gas is sold primarily to Local Distribution Companies (LDCs), utilities, end-users, and integrated major oil companies. Most of the Partnership's natural gas is sold on a monthly basis at either monthly or daily market prices. The Partnership's oil has generally been sold under thirty day evergreen contracts that renew automatically until cancelled by either party. The Partnership believes that the sales prices it receives for oil and natural gas sales are market prices.

For a more in-depth discussion of the Partnership's significant customers, see Note 5 - "Major Customer and Related Parties Information" to the Partnership's financial statements under Item 8 of this Form 10-K. 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 effect 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.

Crude oil and natural gas price volatility could adversely affect our operating results.

The Partnership's revenues and operating results 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. 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;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Our results of operations as well as the carrying value of our oil and gas properties are substantially dependent upon the prices of oil and natural gas, which have declined significantly since June 2014. Despite slight increases in oil and natural gas prices in 2017, prices have remained significantly lower than recent years, which has adversely affected our revenues, operating income, cash flow, and proved reserves. Continued low prices could have a material adverse impact on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained low prices of crude oil and natural gas may further adversely impact our business as follows:

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

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, limited, 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. For example, the Partnership's production at South Timbalier 295 was down for all of second-quarter 2017 for a third-party pipeline reroute, and production from Ship Shoal 258/259 was shut-in from March 2017 through the end of the year as a result of third-party pipeline maintenance, which significantly reduced the Partnership's revenues, earnings, cash flow from operating activities, and liquidity in 2017. Similarly, the Partnership experienced downtime in 2016 and 2015 for pipeline maintenance at South Timbalier 295 and Ship Shoal 258/259, which reduced revenues, earnings and cash flow in each year. If a substantial amount of our production is interrupted at the same time or for an extended period of time, it could adversely affect our cash flow.

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

Current global market conditions, and uncertainty, including the economic instability in Europe and certain emerging markets, are likely to have significant long-term effects. 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.

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

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

Oil and gas operations involve a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents.

The Partnership's operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil and natural gas, including:

- well blowouts, explosions, and cratering;
- pipeline or other facility ruptures and spills;
- fires;
- formations with abnormal pressures;
- equipment malfunctions;
- hurricanes which could affect our operations on and offshore the Gulf Coast, and other natural disasters and weather conditions; and
- surface spillage and water contamination from petroleum constituents, saltwater, or hydraulic fracturing chemical additives

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks, or natural disasters such as hurricanes, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, or fire at a location where our equipment and services are used, or water contamination from hydraulic fracturing chemical additives, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture or surface spillage and water contamination from petroleum constituents or hydraulic fracturing chemical additives could result in extensive environmental pollution and substantial remediation expenses. If a significant amount of our production is interrupted, our containment efforts prove to be ineffective, or litigation arises as the result of a catastrophic occurrence, our cash flows, and, in turn, our results of operations could be materially and adversely affected.

A decline in commodity prices may impact the Partnership's ability to pay distributions to partners, or fund capital expenditures, or both, as cash from operating activities decline.

The Partnership did not make any distributions to Investing Partners during 2017 as a result of the Partnership's expected cash funding for asset retirement obligations (ARO). The Partnership's goal is to maintain cash and cash equivalents in the Partnership at least sufficient to cover its undiscounted future ARO. If oil and natural gas prices remain at or fall below levels at the end of 2017, the Partnership may not be able to make a distribution to Investing Partners during 2018. Declines in cash from operating activities may reduce funds available for capital expenditures.

The distressed financial conditions of our purchasers and operating partners could have an adverse impact on us in the event they are unable to pay us for the products we provide.

Concerns about global economic conditions and the volatility of oil and natural gas prices have had a significant adverse impact on the oil and gas industry. The Partnership is exposed to risk of financial loss from trade, joint venture and other receivables. The Partnership currently sells its crude oil, natural gas, and natural gas liquids through the properties' operators under the joint venture operating agreement and to a variety of purchasers. Some of the joint venture partners that act as operators or their oil and gas purchasers may experience liquidity problems and may not be able to meet their financial obligations. As a result of current economic conditions and the severe decline in oil and natural gas prices, some of our customers and operating partners may experience severe financial problems that may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers or operating partners will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows. Furthermore, the bankruptcy of one or more of our purchasers, customers or operating partners, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. Nonperformance by a trade creditor or joint venture partner could result in significant financial losses.

Reserves and production will decline materially without discoveries or acquisitions of reserves.

The production rate from oil and gas properties generally declines as reserves are depleted and production from offshore wells tends to decline at a faster rate than onshore wells, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through development or exploration drilling, identify and develop additional behind-pipe zones, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase. The Partnership has not and does not plan to engage in future acquisition or exploration activities, therefore, we expect declines in future oil and gas production, which are likely to adversely impact our cash flow and results from operations.

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. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices, except where contractual arrangements exist; therefore, reserve quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies;
- future operating costs and capital expenditures; and
- workover and remediation costs.

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

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 and other remediation activities resulting from operations, subject the lessee to liability for pollution and other damages, limit or constrain operations in affected areas, and require suspension or cessation of operations in affected areas. The Partnership's efforts to limit its exposure to such liability and the operator of the properties ability to comply with applicable laws and regulations may prove inadequate and result in significant adverse effect on our results of operations. In addition, it is possible that the increasingly strict requirements imposed by environmental laws and enforcement policies could require us to make significant capital expenditures. Such capital expenditures could adversely impact our cash flows and our financial condition.

Our operations are subject to governmental risks.

Our operations have been, and at times in the future may be, affected by political developments and by federal, state 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.

In response to the Deepwater Horizon incident in the U.S. Gulf of Mexico in April 2010, and as directed by the Secretary of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) issued new guidelines and regulations regarding safety, environmental matters, drilling equipment, and decommissioning applicable to drilling in the Gulf of Mexico. These regulations imposed additional requirements and caused delays with respect to development and production activities in the Gulf of Mexico.

With respect to oil and gas operations in the Gulf of Mexico, the BOEM has issued Notice to Lessees (NTL) No. 2016-N01 pertaining to the obligations of companies to provide supplemental assurances for performance with respect to plugging, abandonment, decommissioning, and site clearance obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. Under this NTL, the Partnership will likely be required to provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to the Partnership's current ownership interests in various Gulf of Mexico leases. The Partnership will likely satisfy such requirements through the provision of bonds or other forms of security.

New political developments, laws, and the enactment of new or stricter regulations in the Gulf of Mexico or otherwise impacting our operations, and increased liability for companies operating in this sector may adversely impact our results of operations.

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

There has been discussion in the United States regarding legislation or regulation of greenhouse gas (GHG). Any such legislation or regulation, if enacted, could tax or assess some form of 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.

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. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to potential environmental and physical impacts, including possible links to earthquakes. The Partnership may use fracturing techniques 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.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

The Partnership's business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. The Partnership, its Managing Partner and joint venture operators depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate with third party partners, and conduct many of our activities. Unauthorized access to our digital technology could lead to operational disruption, data corruption, or exposure to communication interruption, loss of intellectual property, loss of confidential and fiduciary data, and loss or corruption of reserves or other proprietary information. Also, external digital technologies control nearly all of the oil and gas distribution and refining systems in the United States, which are necessary to transport and market our production. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

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

Exploration for and production of oil and natural gas can be hazardous, involving natural disasters and unforeseen events 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.

If one or more of our operating partners performs poorly or declares bankruptcy, our business, financial condition and results of operations, ability to make distributions to our unitholders and ability to comply with our asset retirement obligations could be adversely affected.

In general, we expect to rely on our operating partners for the day-to-day management and operation of our assets. We will have no control or only limited influence over the day-to-day management and operation of such assets. One or more of our operating partners may perform poorly in operating one or more of our assets for a variety of reasons. If one of our operating partners does not perform well or is forced to declare bankruptcy, we may not be able to ameliorate the adverse effects of poor performance by terminating the operating partner and finding a replacement operating partnership to operate these assets in a timely manner. In such an instance, our business, results of operations, financial condition, ability to make distributions to our unitholders and ability to comply with our asset retirement obligations could be materially adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2017, the Partnership did not have any unresolved comments from the staff of the SEC.

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. 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, 2017, is set forth below:

Lease Block	State	Developed Acreage	
		Gross Acres	Net Acres
Ship Shoal 258, 259	LA	10,141	638
South Timbalier 276, 295, 296	LA	15,000	1,063
		<u>25,141</u>	<u>1,701</u>

At December 31, 2017, 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, 2017, is set forth below:

Lease Block	State	Gas		Oil	
		Gross	Net	Gross	Net
Ship Shoal 258, 259	LA	4	0.25	—	—
South Timbalier 276, 295, 296	LA	1	0.07	18	1.27
		<u>5</u>	<u>0.32</u>	<u>18</u>	<u>1.27</u>

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:

Year	Net Exploratory			Net Development		
	Productive	Dry	Total	Productive	Dry	Total
2017	—	—	—	—	—	—
2016	—	—	—	—	—	—
2015	—	—	—	—	—	—

Production, Pricing and Lease Operating Cost Data

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

Year Ended December 31,	Production			Average Lease Operating Cost per Mcfe	Average Sales Price		
	Oil (Mbbls)	NGLs (Mbbls)	Gas (MMcf)		Oil (Per bbl)	NGLs (Per bbl)	Gas (Per Mcf)
2017							
South Timbalier 295	17	1	39	\$ 3.80	\$ 48.00	\$ 22.89	\$ 3.51
Other fields	—	—	3	8.90	47.44	30.60	3.21
Total	<u>17</u>	<u>1</u>	<u>42</u>	<u>\$ 3.93</u>	<u>\$ 48.00</u>	<u>\$ 23.63</u>	<u>\$ 3.49</u>
2016							
South Timbalier 295	25	2	73	\$ 2.10	\$ 40.33	\$ 15.56	\$ 2.55
Other fields	—	1	33	4.23	35.32	23.39	2.39
Total	<u>25</u>	<u>3</u>	<u>106</u>	<u>\$ 2.40</u>	<u>\$ 40.27</u>	<u>\$ 17.35</u>	<u>\$ 2.50</u>
2015							
South Timbalier 295	25	3	60	\$ 2.26	\$ 53.49	\$ 17.72	\$ 2.77
Other fields	—	1	35	8.65	51.86	26.53	2.89
Total	<u>25</u>	<u>4</u>	<u>95</u>	<u>\$ 3.22</u>	<u>\$ 53.47</u>	<u>\$ 18.96</u>	<u>\$ 2.82</u>

At December 31, 2017, the South Timbalier 295 field contained approximately 90 percent of the Partnership's proved reserves, expressed on an oil-equivalent-barrels basis.

Estimated Proved Reserves and Future Net Cash Flows

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and NGLs 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. Reserve estimates are considered proved if they are economically producible and are supported by either actual production or conclusive formation tests. Estimated reserves that can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have 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, 2017, the Partnership had total estimated proved reserves of 376,161 barrels of crude oil and condensate, 54,192 barrels of NGLs and 1.0 Bcf of natural gas. Combined, these total estimated proved reserves are equivalent to 599,686 barrels of oil. 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, 2017, based on commodity average prices in effect on the first day of each month in 2017, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms.

	Oil (Mbbbls)	NGL (Mbbbls)	Gas (MMcf)
Proved developed	376	54	1,016
Proved undeveloped	—	—	—
Total proved	376	54	1,016

The Partnership's estimates of proved reserves and proved developed reserves at December 31, 2017, 2016, and 2015, 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 Note 10—Supplemental Oil and Gas Disclosures (Unaudited) in the 2017 Consolidated Financial Statements under Item 8 of this Form 10-K. Estimated future net cash flows 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 of the previous 12 months, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms.

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 (Ryder Scott) 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 owned 100 percent at December 31, 2017, is filed as an exhibit to this Form 10-K.

The primary technical person responsible for overseeing the preparation of the Partnership's reserve estimates is Mr. Ali A. Porbandarwala, a Vice President with Ryder Scott. Mr. Porbandarwala has more than nine years of experience in the estimation and evaluation of petroleum reserves 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. *MINE SAFETY DISCLOSURES*

None.

PART II

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

As of December 31, 2017, there were 1,021.5 of the Partnership's Units outstanding held by 912 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 2017, 2016, or 2015.

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.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data for the five years ended December 31, 2017, 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,				
	2017	2016	2015	2014	2013
	(In thousands, except per Unit amounts)				
Total assets	\$ 9,318	\$ 9,420	\$ 13,175	\$ 13,501	\$ 12,799
Partners' capital	\$ 7,283	\$ 7,561	\$ 10,691	\$ 10,973	\$ 10,426
Oil and gas sales	\$ 976	\$ 1,317	\$ 1,707	\$ 2,934	\$ 3,556
Net income (loss)	\$ (257)	\$ (3,135)	\$ (228)	\$ 812	\$ 966
Net income (loss) allocated to:					
Managing Partner	\$ (6)	\$ 35	\$ 47	\$ 271	\$ 326
Investing Partners	(251)	(3,170)	(275)	541	640
	\$ (257)	\$ (3,135)	\$ (228)	\$ 812	\$ 966
Net income (loss) per Investing Partner Unit	\$ (246)	\$ (3,103)	\$ (269)	\$ 530	\$ 626
Cash distributions per Investing Partner Unit	\$ —	\$ —	\$ —	\$ —	\$ —

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 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 following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part II, Item 8 of this Form 10-K, and the Risk Factors information set forth in Part I, Item 1A of this Form 10-K.

The Partnership derives its revenue from the production and sale of crude oil, natural gas and natural gas liquids (NGLs). With only modest levels of production from current wells, the Partnership sells its production at market prices and has not used derivative financial instruments or otherwise engaged in hedging activities. Prices in recent years have remained volatile and this volatility has caused the Partnership's revenues and resulting cash flow from operating activities to fluctuate widely over the years. During 2017, the Partnership's average realized oil price increased 19 percent from 2016, while natural gas prices increased 40 percent. With third-party pipelines coming back on-line during 2018 and rising commodity prices, offset by expected natural depletion on existing wells, the Partnership is anticipating revenues, earnings, and cash flow to rise modestly in 2018 compared to 2017.

During 2017, the Partnership's oil production declined 32 percent as a result of an unexpected third-party pipeline shut-down for repairs at South Timbalier 295 during the second quarter of 2017. Gas production for 2017 declined 61 percent, primarily a result of unplanned maintenance on the Ship Shoal 258/259 third-party pipeline beginning in March of 2017. The pipeline remained shut-down for the remainder of 2017 with operations anticipated to resume during the first quarter of 2018.

The Partnership participates in development drilling and recompletion activities as recommended by the operators of the properties in which the Partnership owns an interest. During 2017, the Partnership's had cash outlays for oil and gas property additions of \$36,115 as the Partnership did not participate in any new drilling projects during 2017, and participated in only two new recompletion projects during the year.

With platform abandonment operations at North Padre Island 969/976 being scheduled to commence and pipeline interruptions and maintenance negatively impacting cash flows, the Partnership did not make any distributions to the Investing Partners during 2017. The Partnership will continue to review available cash balances, scheduled plugging and abandonment activity, oil and gas prices realized by the Partnership for the sale of its production, and the anticipated level of recompletion and repair activity to determine whether there are sufficient funds to make a distribution to Investing Partners in 2018.

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 2017, 2016, and 2015.

Net Income and Revenue

The Partnership reported a net loss of \$0.3 million for 2017 compared to a net loss of \$3.1 million for 2016. On a per Investing Partner Unit basis, the partnership reported a loss of \$246 per Unit in 2017, compared to a net loss of \$3,103 per Unit in 2016. The 2016 net loss included \$2.9 million of non-cash write-downs in the carrying value of the Partnership's oil and gas properties and reduced revenues as a result of lower oil and gas prices compared to the prior year. The Partnership reported a net loss of \$0.2 million in 2015.

Total revenues in 2017 of \$1.0 million decreased 24 percent from 2016 as the result of lower production from extended pipeline maintenance and repairs during 2017, partially offset by higher oil and gas prices. The Partnership's total revenues in 2016 of \$1.3 million decreased 18 percent from 2015 on lower oil and gas prices.

Declines in oil and gas production can generally be expected in future years as a result of normal depletion. Given the small number of producing wells owned by the Partnership, and that production from offshore wells tends to decline at a faster rate than production from 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, gas and NGL production volume and price information is summarized in the following table (gas volumes are presented in thousand cubic feet (Mcf) per day):

	For the Year Ended December 31,				
	2017	Increase (Decrease)	2016	Increase (Decrease)	2015
Gas volume – Mcf per day	114	(61)%	290	12 %	260
Average gas price – per Mcf	\$ 3.49	40 %	\$ 2.50	(11)%	\$ 2.82
Oil volume – barrels per day	46	(32)%	68	(1)%	69
Average oil price – per barrel	\$ 48.00	19 %	\$ 40.27	(25)%	\$ 53.47
NGL volume – barrels per day	3	(57)%	7	(42)%	12
Average NGL price – per barrel	\$ 23.61	36 %	\$ 17.35	(8)%	\$ 18.96

During the second quarter of 2017, South Timbalier was shut down to reroute the existing pipeline. The work was completed towards the end of the third quarter of 2017, and the pipeline was back on-line during the fourth quarter of 2017. Also during the second quarter of 2017, the third-party pipeline at Ship Shoal 258/259 was shut-down for maintenance, which extended through the end of 2017. The Partnership has been informed that the repairs are complete and anticipates Ship Shoal 258/259 to come back on-line in the first quarter of 2018.

Crude Oil Sales

2017 vs. 2016 The Partnership's crude oil sales in 2017 totaled \$806,620, down 20 percent from 2016 on lower production, the result of the South Timbalier 295 pipeline interruption. The Partnership's average realized oil price in 2017 increased 19 percent from 2016, increasing to \$48.00 per barrel in 2017.

2016 vs. 2015 The Partnership's crude oil sales in 2016 totaled \$1.0 million, down 26 percent from 2015 on lower prices. The Partnership's average realized oil price in 2016 decreased 25 percent from 2015, dropping to \$40.27 per barrel in 2016. The Partnership's crude oil volumes were down slightly from 2015.

Natural Gas Sales

2017 vs. 2016 Natural gas sales in 2017 decreased 45 percent from a year ago, totaling \$145,562 on lower production as the result of prolonged repairs on the Ship Shoal 258/259 third-party pipeline. The decrease in production was partially offset by average realized gas prices increasing from \$2.50 per Mcf in 2016 to \$3.49 per Mcf in 2017.

2016 vs. 2015 Natural gas sales in 2016 decreased 1 percent from a year ago, totaling \$0.3 million on lower realized gas prices. The Partnership's average realized gas prices decreased from \$2.82 per Mcf in 2015 to \$2.50 per Mcf in 2016, reducing sales by approximately \$30,000. A 30 Mcf per day, or 12 percent increase in natural gas volumes during 2016 from the same period a year ago nearly offset the impact of lower natural gas prices. The Partnership's increase in gas production in 2016 primarily reflected recompletions at South Timbalier 295 in late 2015.

NGL Sales

The Partnership sold 3 barrels per day of natural gas liquids in 2017, down from 7 barrels per day in 2016. The decrease was the result of the pipeline shutdowns at South Timbalier 295 and Ship Shoal 258/259 during 2017. The decreased production was partially offset by NGL prices increasing 36 percent from 2016, increasing to \$23.61 per barrel. The Partnership sold 7 barrels per day of natural gas liquids in 2016, down from 12 barrels per day in 2015. The decrease reflected lower processed volumes at South Timbalier 295 in 2016 and pipeline downtime at Ship Shoal 258/259. NGL prices in 2016 decreased 8 percent from 2015, dropping to \$17.35 per barrel.

Since the Partnership does not anticipate acquiring additional acreage or conducting exploratory drilling on leases in which it currently holds an interest, declines in oil and gas production can generally be expected in future periods as a result of natural depletion. Also, given the small number of producing wells owned by the Partnership and exposure to inclement weather in the Gulf of Mexico, the Partnership's production may be subject to more volatility than those companies with a larger or more diversified property portfolio.

Operating Expenses

2017 vs. 2016 The Partnership's depreciation, depletion and amortization (DD&A), expressed as a percentage of oil and gas sales, decreased to approximately 27 percent in 2017 from approximately 38 percent in 2016. The dollar amount of recurring DD&A expense for 2017 decreased from the comparable period a year ago as a result of the lower DD&A rate and lower sales volumes from pipeline interruptions. For 2017 and 2016, the Partnership recognized asset retirement obligation (ARO) accretion expense of \$105,135 and \$79,661, respectively. The deferral of abandonment activity at North Padre Island 969/976 and revisions in ARO liability shifted the timing of the Partnership's abandonment obligations and increased accretion expense during 2017.

Lease operating expenses (LOE) for 2017 increased 3 percent from the same period a year ago to \$581,718 in 2017. The slight increase reflects the impact of repair and maintenance work for unexpected shut-ins at South Timbalier 295 and Ship Shoal 258/259 and operating costs that correspond to increases in commodity prices. Gathering and transportation costs for the delivery of oil and gas totaled \$2,495, the result of lower production from pipeline downtime at Ship Shoal 258/259 and a change in oil marketing arrangements for South Timbalier 295. Administrative expenses for 2017 decreased 9 percent compared to 2016.

Under the full cost method of accounting, the Partnership is required to review the carrying value of its proved oil and gas properties each quarter. Under these rules, capitalized costs of oil and gas properties, net of accumulated DD&A, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves discounted at 10 percent per annum. Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements. The Partnership did not recognize a write-down for the carrying value of

its oil and gas properties during 2017. The Partnership wrote-down the carrying value of its oil and gas properties by approximately \$2.9 million during 2016. The write-downs are reflected as additional DD&A expense. If commodity prices experience declines to levels lower than prices realized in the previous 12 months, the Partnership may be required to recognize non-cash write-downs of the carrying value of its oil and gas properties in future periods.

2016 vs. 2015 The Partnership's DD&A, expressed as a percentage of oil and gas sales, rose to approximately 38 percent in 2016 from approximately 28 percent in 2015. The increase in the rate as a percentage of oil and gas sales in 2015 reflected the impact of declining oil and gas prices. The dollar amount of recurring DD&A expense for 2016 increased from the comparable period a year ago as a result of the higher DD&A rate. For 2016 and 2015, the Partnership recognized asset retirement obligation accretion of \$79,661 and \$126,687, respectively. Abandonment activity during 2015 at Matagorda Island 681/682 and North Padre Island 969/976 reduced the Partnership's abandonment obligations and related accretion expense.

LOE for 2016 were down 25 percent from the prior year, decreasing to \$0.6 million in 2016. The decrease reflects the impact of permanently shutting-in North Padre Island 969/976 and operating costs that have been trending downward as a response to lower commodity prices. In addition, the operator of the properties has been delaying discretionary repair work and other costs in light of reduced oil and gas prices and cash flow. Gathering and transportation costs for the delivery of oil and gas decreased over 30 percent from the same period in 2015 primarily a result of a change in oil marketing arrangements on the South Timbalier 295. Administrative expenses for 2016 decreased four percent compared to the same period in 2015.

The Partnership's oil and natural gas is generally sold utilizing two common types of agreements, both of which include a transportation charge. One is a netback arrangement, under which oil or natural gas is sold at the wellhead and the Partnership collects a price, net of transportation incurred by the operator or purchaser. In this case, the Partnership records sales at the price received from the final purchaser which is net of transportation costs. Under the other arrangement, the oil or natural gas is sold at a specific delivery point, the operator or Partnership pays transportation to a carrier and receives from the purchaser a price with no transportation deduction. In this case, the Partnership records the separate transportation cost as gathering and transportation costs.

Capital Resources and Liquidity

The Partnership's primary capital resource is net cash provided by operating activities, which totaled a cash inflow of \$138,687 for 2017 and a cash outflow of \$177,543 for 2016. The increase from 2016 reflected lower abandonment spending in the current year. Net cash provided by operating activities totaled \$55,546 for 2015.

At December 31, 2017, the Partnership had approximately \$5.1 million in cash and cash equivalents, up slightly from the end of 2016. The Partnership's goal is to maintain cash and cash equivalents at least sufficient to cover the undiscounted value of its future asset retirement obligation liability. The Partnership also plans to reserve funds for repairs, which may disrupt the Partnership's production.

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 and economic conditions (especially in the Middle East), the foreign and domestic supply of oil and natural gas, the price of foreign imports, the level of consumer demand, weather 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 generally be expected in future years as a result of normal depletion and the Partnership's non-participation in acquisition or exploration activities. Based on production estimates from independent engineers and current market conditions, the Partnership forecasts it will be able to meet its liquidity needs for routine operations in 2018 and 2019.

Approximately 89 percent of the Partnership's total proved 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 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, to be in-line with cash from operating activities. 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 existing 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 costs. The Partnership did not sell any properties in 2017, 2016, or 2015.

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. To the extent it has discretion, the Partnership allocates available capital to investment in the Partnership's properties so as to maximize production and resultant cash flow. The Partnership had no outstanding debt or lease commitments at December 31, 2017. The Partnership did not have any contractual obligations as of December 31, 2017, other than the liability for dismantlement and abandonment costs of its oil and gas properties. The Partnership has recorded a separate liability for this asset retirement obligation as discussed in the notes to the financial statements included in this annual report on Form 10-K.

During each of the last three years, the Partnership had modest cash outlays for oil and gas property additions as it did not participate in any new drilling projects. The Partnership participated in two recompletion projects at South Timbalier 295 in 2017. The Partnership paid cash settlements for ARO liabilities totaling \$12,259 in 2017, \$0.3 million in 2016, and \$0.5 million in 2015.

Based on preliminary information available to the Partnership, it anticipates capital expenditures will be less than \$200,000 in 2018 for pipeline and recompletion projects at South Timbalier 295. Additionally, \$540,000 is estimated to be spent in 2018 to abandon several wells currently shut-in at Ship Shoal 258/259 and to remove the platforms at North Padre Island 969/976. The abandonment activity at North Padre Island 969/976 was originally scheduled to commence in 2016, but has been deferred to the middle of 2018 and possibly 2019 pending approval from regulators. Such estimates may change based on realized oil and gas prices, drilling and recompletion results, rates charged by contractors or changes by the operator to their development or abandonment plans.

Because of low oil and gas prices, pipeline interruptions to production, and the need to reserve cash for future asset retirement obligations, no distributions were made to Investing Partners during 2017. The Partnership also made no distribution to Investing Partners during 2016 as a result of low product prices and the large amount of pending plugging costs at North Padre Island 969/976.

The amount of future distributions will be dependent on actual and expected production levels, realized and anticipated 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's goal is to maintain cash and cash equivalents in the Partnership at least sufficient to cover the undiscounted value of its future asset retirement obligations. The Partnership will continue to review available cash balances, cash requirements for plugging and abandonment activity, oil and gas prices realized by the Partnership for the sale of its production, especially in light of lower commodity prices in recent years, and the level of drilling and recompletion activity to determine whether there are sufficient funds to make a distribution to Investing Partners in 2018.

With respect to oil and gas operations in the Gulf of Mexico, the BOEM has issued Notice to Lessees (NTL) No. 2016-N01 pertaining to the obligations of companies to provide supplemental assurances for performance with respect to plugging, abandonment, decommissioning, and site clearance obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. Under this NTL, the Partnership will likely be required to provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to the Partnership's current ownership interests in various Gulf of Mexico leases. The Partnership will likely satisfy such requirements through the provision of bonds or other forms of security. Management does not believe the ultimate satisfaction of the NTL requirements will adversely affect the Partnership's overall liquidity.

As provided in the Amended Partnership Agreement, a first right of presentment valuation was computed during the first quarter of 2017. The per-unit value was determined to be \$9,242 based on the valuation date of December 31, 2016. A second right of presentment valuation was computed during October 2017 and the per-unit value was determined to be \$8,794 based on a valuation date of June 30, 2017. The Partnership did not repurchase any Investing Partner Units (Units) during 2017 as a result of the Partnership's limited amount of cash available for discretionary purposes. The per-unit right of presentment value computed during the first quarter of 2016 based on the valuation date of December 31, 2015, was \$6,057 and the second per-unit right of presentment in 2016 was \$6,091 based on a valuation date of June 30, 2016. The Partnership did not repurchase any Units during 2016. Pursuant to the Amended Partnership Agreement, the Partnership has no obligation to repurchase any Units presented to the extent it determines that it has insufficient funds for such purchases.

There will be two rights of presentment in 2018, 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.

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.

Insurance

The Managing Partner maintains insurance coverage that includes coverage for physical damage to the Partnership's oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. The insurance coverage includes deductibles, which must be met prior to recovery. Additionally, the Managing Partner's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

The Managing Partner's various insurance policies also provide coverage for, among other things, liability related to negative environmental impacts of a sudden pollution, charterer's legal liability and general liability, employer's liability and auto liability. The Managing Partner's service agreements, including drilling contracts, generally indemnify Apache and the Partnership for injuries and death of the service provider's employees as well as contractors and subcontractors hired by the service provider.

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. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. The following is a discussion of Partnership's most critical accounting policies:

Reserve Estimates

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 are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of production, except where prices are defined by contractual arrangements.

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 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 ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with Partnership's oil and gas properties. The Partnership utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. 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. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Partnership's major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to its natural gas production. Prices received for oil and gas production continue to be volatile and unpredictable. The Partnership has not used derivative financial instruments or otherwise engaged in hedging activities during 2017 or 2016.

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 production 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 2017, monthly oil price realizations ranged from a low of \$40.28 per barrel to a high of \$59.11 per barrel. Gas price realizations ranged from a monthly low of \$2.96 per Mcf to a monthly high of \$3.92 per Mcf during the same period. Based on the Partnership's average daily production for 2017, a \$1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately \$17,000 and a \$0.10 per Mcf change in the weighted average realized price of natural gas would have increased or decreased revenues for the year by approximately \$4,000. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2017. 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 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.

ADDITIONAL INFORMATION ABOUT THE PARTNERSHIP

Environmental Compliance

As an owner or lessee and operator of oil and gas properties and facilities, the Partnership is subject to numerous federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Although environmental requirements have a substantial impact upon the energy industry, as a whole, we do not believe that these requirements affect us differently, to any material degree, than other companies in our industry.

The Partnership has made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry. The Managing Partner has established policies for continuing compliance with environmental laws and regulations, including regulations applicable to the Partnership's operations. The costs incurred under these policies and procedures are inextricably connected to normal operating expenses such that we are unable to separate expenses related to environmental matters; however, the Partnership does not believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on its capital expenditures or earnings.

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, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework (2013)*. Based on our assessment, management believes that the Partnership maintained effective internal control over financial reporting as of December 31, 2017.

/s/ John J. Christmann IV
*Chief Executive Officer and President
(principal executive officer)
of Apache Corporation, Managing Partner*

/s/ Stephen J. Riney
*Executive Vice President and Chief Financial Officer (principal financial
officer)
of Apache Corporation, Managing Partner*

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

Houston, Texas
February 22, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Apache Offshore Investment Partnership:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Apache Offshore Investment Partnership (the Partnership) as of December 31, 2017 and 2016, the related statements of consolidated operations, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2002.

Houston, Texas
February 22, 2018

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2017	2016	2015
REVENUES:			
Oil and gas sales	\$ 976,395	\$ 1,317,075	\$ 1,707,495
Other revenue (loss)	—	—	(84,249)
Interest income	32,104	7,639	88
	<u>1,008,499</u>	<u>1,324,714</u>	<u>1,623,334</u>
EXPENSES:			
Depreciation, depletion and amortization			
Recurring	261,228	507,051	478,748
Additional	—	2,873,180	—
Asset retirement obligation accretion	105,135	79,661	126,687
Lease operating expenses	581,718	567,434	756,598
Gathering and transportation costs	2,495	84,617	124,806
Administrative	315,392	348,000	364,000
	<u>1,265,968</u>	<u>4,459,943</u>	<u>1,850,839</u>
NET LOSS	<u>\$ (257,469)</u>	<u>\$ (3,135,229)</u>	<u>\$ (227,505)</u>
NET INCOME (LOSS) ALLOCATED TO:			
Managing Partner	\$ (5,899)	\$ 34,361	\$ 47,101
Investing Partners	(251,570)	(3,169,590)	(274,606)
	<u>\$ (257,469)</u>	<u>\$ (3,135,229)</u>	<u>\$ (227,505)</u>
NET LOSS PER INVESTING PARTNER UNIT	<u>\$ (246)</u>	<u>\$ (3,103)</u>	<u>\$ (269)</u>
WEIGHTED AVERAGE INVESTING PARTNER UNITS OUTSTANDING	<u>1,021.5</u>	<u>1,021.5</u>	<u>1,021.5</u>

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	\$ (257,469)	\$ (3,135,229)	\$ (227,505)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	261,228	3,380,231	478,748
Asset retirement obligation accretion	105,135	79,661	126,687
Changes in operating assets and liabilities:			
Accrued receivables	30,211	24,756	161,566
Receivable from/payable to Apache Corporation	8,200	(19,606)	17,274
Other payables	—	(84,249)	84,249
Accrued operating expenses	3,641	(132,350)	(113,539)
Asset retirement expenditures	(12,259)	(290,757)	(471,934)
Net cash provided by (used in) operating activities	138,687	(177,543)	55,546
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas properties	(36,115)	(38,231)	(30,013)
Net cash used in investing activities	(36,115)	(38,231)	(30,013)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Contributions from Managing Partner	—	4,990	—
Distributions to Managing Partner	(20,755)	—	(54,584)
Net cash provided by (used in) financing activities	(20,755)	4,990	(54,584)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	81,817	(210,784)	(29,051)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	5,035,668	5,246,452	5,275,503
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$ 5,117,485	\$ 5,035,668	\$ 5,246,452

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

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
CONSOLIDATED BALANCE SHEET**

	<u>December 31, 2017</u>	<u>December 31, 2016</u>
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 5,117,485	\$ 5,035,668
Accrued revenues receivable	92,881	123,092
Receivable from Apache Corporation	—	4,799
	<u>5,210,366</u>	<u>5,163,559</u>
OIL AND GAS PROPERTIES, on the basis of full cost accounting:		
Proved properties	195,005,011	194,893,233
Less – Accumulated depreciation, depletion and amortization	(190,897,856)	(190,636,628)
	<u>4,107,155</u>	<u>4,256,605</u>
	<u>\$ 9,317,521</u>	<u>\$ 9,420,164</u>
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Payable to Apache Corporation	3,401	—
Current asset retirement obligation	544,939	—
Accrued operating expenses	100,855	97,214
Accrued development costs	141,373	9,410
	<u>790,568</u>	<u>106,624</u>
ASSET RETIREMENT OBLIGATION	<u>1,244,328</u>	<u>1,752,691</u>
PARTNERS' CAPITAL:		
Managing Partner	419,576	446,230
Investing Partners (1,021.5 units outstanding)	6,863,049	7,114,619
	<u>7,282,625</u>	<u>7,560,849</u>
	<u>\$ 9,317,521</u>	<u>\$ 9,420,164</u>

The accompanying notes to consolidated 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, 2014	\$ 414,362	\$ 10,558,815	\$ 10,973,177
Distributions	(54,584)	—	(54,584)
Net income (loss)	47,101	(274,606)	(227,505)
BALANCE, DECEMBER 31, 2015	\$ 406,879	\$ 10,284,209	\$ 10,691,088
Contributions	4,990	—	4,990
Net income (loss)	34,361	(3,169,590)	(3,135,229)
BALANCE, DECEMBER 31, 2016	\$ 446,230	\$ 7,114,619	\$ 7,560,849
Distributions	(20,755)	—	(20,755)
Net loss	(5,899)	(251,570)	(257,469)
BALANCE, DECEMBER 31, 2017	<u>\$ 419,576</u>	<u>\$ 6,863,049</u>	<u>\$ 7,282,625</u>

The accompanying notes to consolidated 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 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, 2017. 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. The Partnership's working interests in the two remaining venture prospects at December 31, 2017 range from 6.29 percent to 7.08 percent. The two remaining venture prospects are both located offshore Louisiana.

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 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.

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. The Partnership did not offer to purchase any Units from Investing Partners in 2017, 2016, or 2015 as a result of the limited amount of cash available for discretionary purposes.

The Partnership is not in a position to predict how many Units will be presented for repurchase during 2018; 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.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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, 2014	\$ 9,975,347	\$ 9,765
June 30, 2015	10,042,327	9,831
December 31, 2015	6,187,080	6,057
June 30, 2016	6,222,171	6,091
December 31, 2016	9,440,733	9,242
June 30, 2017	8,983,454	8,794

Investing Partner Units Outstanding:	2017	2016	2015
Balance, beginning of year	1,021.5	1,021.5	1,021.5
Repurchase of Partnership Units	—	—	—
Balance, end of year	1,021.5	1,021.5	1,021.5

Capital Contributions

A total of \$85,000 per Unit, or approximately 57 percent, of investor subscription had been called through December 31, 2017. 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, 2017.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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.

Use of Estimates

The preparation of financial statements in conformity with GAAP and the disclosure of contingent assets and liabilities requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Partnership bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. The Partnership evaluates its estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of its financial statements and changes in these estimates are recorded when known. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows therefrom (see Note 10 – Supplemental Oil and Gas Disclosures) and the assessment of asset retirement obligations (see Note 8 – Asset Retirement Obligation).

Cash Equivalents

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. As of December 31, 2017 and 2016, the Partnership had \$5.1 million and \$5.0 million, respectively, of cash and cash equivalents.

Oil and Gas Properties

The Partnership follows 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. All costs related to 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 expense and reflected as additional DD&A in the accompanying statement of consolidated operations. Estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements. As a result of the ceiling limitation, the Partnership recorded non-cash write-downs of the carrying value of its proved oil and gas properties totaling \$2,873,180 during 2016. The Partnership did not record any write-downs of capitalized costs during 2017 or 2015. See Note 10 - Supplemental Oil and Gas Disclosures for a discussion on the calculation of estimated future net cash flows.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

Asset Retirement Costs and Obligation

The initial estimated asset retirement obligation related to property and equipment is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to oil and gas properties on the consolidated balance sheet. If the fair value of the recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations. Accretion expense on the liability is recognized over the estimated productive life of the related assets.

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. At December 31, 2017 and 2016, the Partnership did not have any liability recorded for gas 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.

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 (Loss) Per Investing Unit

The net income (loss) 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.

Receivable from / Payable to Apache Corporation

The receivable from/payable to Apache Corporation, the Partnership's 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.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

New Pronouncements Issued But Not Yet Adopted

In June 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses.” The standard changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, held-to-maturity debt securities and loans, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowance for losses. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted for a fiscal year beginning after December 15, 2018, including interim periods within that fiscal year. The Partnership does not expect to adopt the guidance early. Entities will apply the standard's provisions as a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is adopted. The Partnership is evaluating the new guidance and does not believe this standard will have a material impact on its consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842),” requiring lessees to recognize lease assets and lease liabilities for most leases classified as operating leases under previous U.S. GAAP. The guidance is effective for fiscal years beginning after December 15, 2018, and the Partnership will be required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements. Early adoption is permitted; however, the Partnership does not intend to early adopt. The Partnership is currently evaluating the impact of adopting this standard on its consolidated financial statements.

In May 2014, the FASB and the International Accounting Standards Board (IASB) issued a joint revenue recognition standard, ASU 2014-9, “Revenue from Contracts with Customers (Topic 606).” The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers, and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires companies to recognize revenue to depict the transfer of goods or services to customers in amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods or services. The guidance is effective for annual and interim periods beginning after December 15, 2017. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The Partnership adopted the new standard on January 1, 2018, utilizing the modified retrospective approach. Based on the Partnership's evaluation, the adoption of this ASU does not have a material impact on net earnings. The Partnership continues to evaluate the disclosure requirements, develop an accounting policy, and implement changes to the relevant business processes and the control activities within them as a result of the provisions of this ASU.

3. COMPENSATION TO AFFILIATES

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,		
	2017	2016	2015
	(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	\$ 252	\$ 278	\$ 291
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	\$ —	\$ —	\$ —

Apache operated certain Partnership properties through September 30, 2013, at which time Fieldwood Energy LLC purchased Apache’s interest in South Timbalier 295 and Ship Shoal 258/259 and became operator of these properties. Billings to the Partnership were made on the same basis as to unaffiliated third parties or at prevailing industry rates.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

	2017	2016	2015
	(In thousands)		
Oil and Gas Properties			
Balance, beginning of year	\$ 194,893	\$ 195,037	\$ 194,691
Costs incurred during the year:			
Development –			
Investing Partners	104	(126)	314
Managing Partner	8	(18)	32
Balance, end of year	<u>\$ 195,005</u>	<u>\$ 194,893</u>	<u>\$ 195,037</u>

Development costs for 2017 and 2016 include negative revisions of \$66 thousand and \$179 thousand, respectively, for estimated abandonment cost and the deferral of final platform abandonment at North Padre Island 969/976 until mid-2018. Removal of the platforms and final abandonment activity was previously expected to occur during 2016. Approximately \$178 thousand of capital costs were incurred in 2017 for participation in pipeline and recompletion projects at South Timbalier 295, and approximately \$35 thousand of capital costs were incurred in 2016 for participation in a recompletion project at Ship Shoal 258/259. Development costs in 2015 included \$0.3 million on recompletion costs and abandonment activity.

	Managing Partner	Investing Partners	Total
	(In thousands)		
Accumulated Depreciation, Depletion and Amortization			
Balance, December 31, 2014	\$ 21,054	\$ 165,724	\$ 186,778
Provision	15	463	478
Balance, December 31, 2015	\$ 21,069	\$ 166,187	\$ 187,256
Provision	22	3,359	3,381
Balance, December 31, 2016	\$ 21,091	\$ 169,546	\$ 190,637
Provision	13	248	261
Balance, December 31, 2017	<u>\$ 21,104</u>	<u>\$ 169,794</u>	<u>\$ 190,898</u>

The Partnership's aggregate DD&A expense as a percentage of oil and gas sales for 2017, 2016, and 2015 was 27 percent, 38 percent and 28 percent, respectively. As more fully described in Footnote 2 above, as a result of the full-cost method of accounting ceiling limitation, the Partnership recorded non-cash write-downs of the carrying value of its proved oil and gas properties totaling \$2,873,180 during 2016.

5. MAJOR CUSTOMER AND RELATED PARTIES INFORMATION

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

Remittances from Fieldwood Energy LLC accounted for 18 percent, 43 percent, and 100 percent of the Partnership's oil and gas sales for the years 2017, 2016, and 2015, respectively. Approximately 82 percent and 57 percent of the Partnership's oil and gas sales in 2017 and 2016, respectively, were to Chevron Products Company.

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.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

6. FAIR VALUE MEASUREMENTS

Certain assets and liabilities are reported at fair value on a recurring basis in the Partnership's consolidated balance sheet. The following methods and assumptions were used to estimate the fair values:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable -

As of December 31, 2017 and December 31, 2016, the carrying amounts approximate fair value because of the short-term nature or maturity of these instruments.

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 and local 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 the Partnership is not fully insured against all environmental risks.

With respect to oil and gas operations in the Gulf of Mexico, the BOEM has issued Notice to Lessees (NTL) No. 2016-N01 pertaining to the obligations of companies to provide supplemental assurances for performance with respect to plugging, abandonment, decommissioning, and site clearance obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. Under this NTL, the Partnership will likely be required to provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to the Partnership's current ownership interests in various Gulf of Mexico leases. The Partnership will likely satisfy such requirements through the provision of bonds or other forms of security.

8. ASSET RETIREMENT OBLIGATION

The following table describes the changes to the Partnership's asset retirement obligation (ARO) liability for the years ended December 31, 2017 and 2016:

	2017	2016
Asset retirement obligation at beginning of year	\$ 1,752,691	\$ 1,852,113
Accretion expense	105,135	79,661
Liabilities settled	(2,849)	—
Revisions in estimated liabilities	(65,710)	(179,083)
Asset retirement obligation at end of year	\$ 1,789,267	\$ 1,752,691
Less current portion	(544,939)	—
Asset retirement obligation, long-term	\$ 1,244,328	\$ 1,752,691

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 estimates from property operators and current market 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 periods presented. The current portion of the ARO liability represents the retirement obligation expected to be incurred in the next twelve months.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

For 2017, a negative revision to ARO liability was recorded to reflect a reduction in estimated cost and the deferral of final platform abandonment at North Padre Island 969/976 to the middle of 2018 and possibly 2019 pending approval from regulators.

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:

	2017	2016	2015
Net partnership ordinary income (loss) for federal income tax reporting purposes	\$ 5,948	\$ 165,691	\$ (589,078)
Plus: Items of current expense for tax reporting purposes only –			
Intangible drilling cost	33,479	36,920	29,302
Dismantlement and abandonment cost	2,849	(2,969)	773,696
Abandonment expense	—	—	38,419
Tax depreciation	66,618	125,021	125,591
	<u>102,946</u>	<u>158,972</u>	<u>967,008</u>
Less: full cost DD&A expense	(261,228)	(3,380,231)	(478,748)
Less: asset retirement obligation accretion	(105,135)	(79,661)	(126,687)
Net income (loss)	<u>\$ (257,469)</u>	<u>\$ (3,135,229)</u>	<u>\$ (227,505)</u>

The Partnership's tax bases in net oil and gas properties at December 31, 2017, and 2016 was \$2,335,252 and \$2,562,093, respectively, lower than the 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, 2017, and 2016.

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,	
	2017	2016
Liabilities for federal income tax purposes	\$ 245,629	\$ 106,624
Asset retirement liability	1,789,267	1,752,691
Liabilities under accounting principles generally accepted in the United States	<u>\$ 2,034,896</u>	<u>\$ 1,859,315</u>

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

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

10. SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

Oil and Gas Reserve Information

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

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)

	2017			2016			2015		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
<u>Proved Reserves</u>									
Beginning of year	365	53	985	389	58	1,064	425	77	1,250
Extensions, discoveries and other additions	—	—	—	—	—	—	—	—	—
Revisions of previous estimates	28	2	73	1	(2)	27	(10)	(15)	(91)
Production	(17)	(1)	(42)	(25)	(3)	(106)	(26)	(4)	(95)
End of year	<u>376</u>	<u>54</u>	<u>1,016</u>	<u>365</u>	<u>53</u>	<u>985</u>	<u>389</u>	<u>58</u>	<u>1,064</u>
<u>Proved Developed</u>									
Beginning of year	365	53	985	389	58	1,064	425	77	1,250
End of year	<u>376</u>	<u>54</u>	<u>1,016</u>	<u>365</u>	<u>53</u>	<u>985</u>	<u>389</u>	<u>58</u>	<u>1,064</u>

Oil includes crude oil and condensate.

All the Partnership's reserves as of December 31, 2017 are located on federal lease tracts in the Gulf of Mexico, offshore Louisiana. Approximately 89 percent of the Partnership's current 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 now not 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 is reflected in the Partnership's standardized measure under Future Net Cash Flows.

Future Net Cash Flows

Future cash inflows as of December 31, 2017, 2016, and 2015 were calculated using an unweighted arithmetic average of oil and gas prices in effect on the first day of each month in the respective year, except where prices are defined by contractual arrangements. 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.

**APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

Discounted Future Net Cash Flows Relating to Proved Reserves

	December 31,		
	2017	2016	2015
	(In thousands)		
Future cash inflows	\$ 25,968	\$ 20,675	\$ 24,388
Future production costs	(7,808)	(8,277)	(7,938)
Future development costs	(3,957)	(4,282)	(4,438)
Net cash flows	14,203	8,116	12,012
10 percent annual discount rate	(5,971)	(3,445)	(5,419)
Discounted future net cash flows	\$ 8,232	\$ 4,671	\$ 6,593

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

	For the Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Sales, net of production costs	\$ (391)	\$ (665)	\$ (826)
Net change in prices and production costs	2,821	(1,900)	(12,084)
Revisions of quantities	734	42	(532)
Discoveries and improved recoveries, net of cost	—	—	—
Accretion of discount	467	659	1,873
Changes in future development costs	147	61	198
Changes in production rates and other	(217)	(119)	(762)
	\$ 3,561	\$ (1,922)	\$ (12,133)

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
(In thousands, except per Unit amounts)					
2017					
Revenues	\$ 330	\$ 164	\$ 250	\$ 264	\$ 1,008
Expenses	370	290	281	324	1,265
Net loss	<u>\$ (40)</u>	<u>\$ (126)</u>	<u>\$ (31)</u>	<u>\$ (60)</u>	<u>\$ (257)</u>
Net income (loss) allocated to:					
Managing Partner	\$ 8	\$ (17)	\$ 5	\$ (2)	\$ (6)
Investing Partners	(48)	(109)	(36)	(58)	(251)
	<u>\$ (40)</u>	<u>\$ (126)</u>	<u>\$ (31)</u>	<u>\$ (60)</u>	<u>\$ (257)</u>
Net loss per Investing Partner Unit ⁽¹⁾	<u>\$ (48)</u>	<u>\$ (107)</u>	<u>\$ (36)</u>	<u>\$ (55)</u>	<u>\$ (246)</u>
2016					
Revenues	\$ 315	\$ 381	\$ 331	\$ 298	\$ 1,325
Expenses ⁽²⁾	1,722	1,852	571	315	4,460
Net loss	<u>\$ (1,407)</u>	<u>\$ (1,471)</u>	<u>\$ (240)</u>	<u>\$ (17)</u>	<u>\$ (3,135)</u>
Net income (loss) allocated to:					
Managing Partner	\$ (3)	\$ 12	\$ 14	\$ 12	\$ 35
Investing Partners	(1,404)	(1,483)	(254)	(29)	(3,170)
	<u>\$ (1,407)</u>	<u>\$ (1,471)</u>	<u>\$ (240)</u>	<u>\$ (17)</u>	<u>\$ (3,135)</u>
Net loss per Investing Partner Unit ⁽¹⁾	<u>\$ (1,375)</u>	<u>\$ (1,452)</u>	<u>\$ (248)</u>	<u>\$ (28)</u>	<u>\$ (3,103)</u>

(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.

(2) In 2016, expenses include non-cash writedowns of the Partnership's oil and gas properties totaling \$2.9 million. Approximately \$1.3 million, \$1.4 million, and \$0.2 million were recognized in the first, second, and third quarters of 2016, respectively.

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

The financial statements for the fiscal years ended December 31, 2017, 2016 and 2015, included in this report, have been audited by Ernst & Young LLP, independent registered public accounting firm, as stated in their audit report appearing herein. There have been no changes in or disagreements with the accountants during the periods presented.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

John J. Christmann IV, the Managing Partner's Chief Executive Officer and President (in his capacity as principal executive officer), and Stephen J. Riney, the Managing Partner's Executive Vice President and Chief Financial Officer (in his capacity as principal financial officer), evaluated the effectiveness of the Partnership's disclosure controls and procedures as of December 31, 2017, 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 under 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, 2017, that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

Management's Annual 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 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, 2017, that has materially affected, or is reasonably likely to materially affect the Partnership's internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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 2018 annual meeting of stockholders of Apache (the Apache Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, 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 and Ethics (Code of Conduct), and revised it in September 2017. The revised Code of Conduct also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access Apache’s Code of Conduct on the “Governance” page of Apache’s website at www.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 Affiliates” 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 Table,” “Outstanding Equity Awards at Fiscal Year-End Table,” “Option Exercises and Stock Vested Table,” “Non-Qualified Deferred Compensation Table,” “Potential Payments Upon Termination or Change-in-Control,” and “Director Compensation Table” in the Apache Proxy Statement is incorporated herein by reference.

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

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, 2017. 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, AND DIRECTOR INDEPENDENCE

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. The Partnership itself has no directors. Information concerning the directors of Apache set forth under the caption “Director Independence” in the Apache Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING 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 “Ratification of Appointment of Independent Auditors” in the Apache Proxy Statement incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- 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
- P3.1 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).
- P3.2 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).
- P3.3 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).
- P10.1 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).
- P10.2 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).
- P10.3 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.](#)
- P99.2 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, 2018, relating to the 2018 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).
- *101.INS XBRL Instance Document.
- *101.SCH XBRL Taxonomy Schema Document.
- *101.CAL XBRL Calculation Linkbase Document.
- *101.DEF XBRL Definition Linkbase Document.
- *101.LAB XBRL Label Linkbase Document.
- *101.PRE XBRL Presentation Linkbase Document.

* Filed herewith.

P Filed previously in paper format.

b. See a (3) above.

c. See a (2) above.

ITEM 16. FORM 10-K SUMMARY

None.

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

Dated: February 22, 2018

/s/ John J. Christmann IV

John J. Christmann IV

Chief Executive Officer and President

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 John J. Christmann IV, Stephen J. Riney 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.

<u>Name</u>	<u>Title</u>	<u>Date</u>
<u>/s/ John J. Christmann IV</u> John J. Christmann IV	Director, Chief Executive Officer and President (principal executive officer)	February 22, 2018
<u>/s/ Stephen J. Riney</u> Stephen J. Riney	Executive Vice President and Chief Financial Officer (principal financial officer)	February 22, 2018
<u>/s/ Rebecca A. Hoyt</u> Rebecca A. Hoyt	Senior Vice President, Chief Accounting Officer and Controller (principal accounting officer)	February 22, 2018
<u>/s/ Annell R. Bay</u> Annell R. Bay	Director	February 22, 2018
<u>/s/ Chansoo Joung</u> Chansoo Joung	Director	February 22, 2018
<u>/s/ Rene R. Joyce</u> Rene R. Joyce	Director	February 22, 2018
<u>/s/ George D. Lawrence</u> George D. Lawrence	Director	February 22, 2018
<u>/s/ John E. Lowe</u> John E. Lowe	Director, Non-Executive Chairman of the Board	February 22, 2018
<u>/s/ William C. Montgomery</u> William C. Montgomery	Director	February 22, 2018
<u>/s/ Amy H. Nelson</u> Amy H. Nelson	Director	February 22, 2018
<u>/s/ Rodman D. Patton</u> Rodman D. Patton	Director	February 22, 2018
<u>/s/ Daniel W. Rabun</u> Daniel W. Rabun	Director	February 22, 2018
<u>/s/ Peter A. Ragauss</u> Peter A. Ragauss	Director	February 22, 2018



RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580

FAX (713) 651-0849

1100 LOUISIANA SUITE 4600

HOUSTON, TEXAS 77002-5294

TELEPHONE (713) 651-9191

EXHIBIT 23.1

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, 2017, and to the inclusion of our report, dated January 31, 2018, 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 22, 2018

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

CERTIFICATIONS

I, John J. Christmann IV, 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/ John J. Christmann IV

John J. Christmann IV

Chief Executive Officer and President

(principal executive officer) of Apache Corporation, Managing Partner

Date: February 22, 2018

CERTIFICATIONS

I, Stephen J. Riney, 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/ Stephen J. Riney

Stephen J. Riney

Executive Vice President and Chief Financial Officer

(principal financial officer) of Apache Corporation, Managing Partner

Date: February 22, 2018

APACHE OFFSHORE INVESTMENT PARTNERSHIP
by Apache Corporation, Managing Partner

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

I, John J. Christmann IV, 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 ending December 31, 2017, 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/ John J. Christmann IV

By: John J. Christmann IV
Title: Chief Executive Officer and President (principal executive officer)
of Apache Corporation, Managing Partner

Date: February 22, 2018

I, Stephen J. Riney, 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 ending December 31, 2017, 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/ Stephen J. Riney

By: Stephen J. Riney
Title: Executive Vice President and Chief Financial Officer (principal financial officer)
of Apache Corporation, Managing Partner

Date: February 22, 2018

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, 2017

/s/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.

TBPE License No. 107652

Senior Vice President

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

[SEAL]

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS



RYDER SCOTT COMPANY

PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600

HOUSTON, TEXAS 77002-5294

FAX (713) 651-0849
TELEPHONE (713) 651-9191

January 31, 2018

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

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production and income attributable to certain leasehold and royalty interests in the Shell Offshore Venture for Apache Corporation (Apache) as of December 31, 2017. Additionally, at Apache's request, this report includes an estimate of the probable and possible reserves, but does not address the future production or income attributable to the probable and possible reserve quantities contained herein. 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 of the United States Securities and Exchange Commission (SEC) contained in 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 January 25, 2018, are presented herein.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved, probable and possible liquid hydrocarbon reserves and 100 percent of the total net proved, probable and possible gas reserves of the Shell Offshore Venture for Apache as of December 31, 2017.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2017, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of 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, 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 in the following table.

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

As of December 31, 2017

	Proved		
	Developed		Total Proved
	Producing	Non-Producing	
<u>Net Remaining Reserves</u>			
Oil/Condensate – Barrels	41,092	335,069	376,161
Plant Products – Barrels	7,705	46,487	54,192
Gas – MMCF	114	902	1,016
<u>Income Data</u>			
Future Gross Revenue	\$2,895,975	\$23,071,527	\$25,967,502
Deductions	<u>1,590,781</u>	<u>10,173,130</u>	<u>11,763,911</u>
Future Net Income (FNI)	\$ 1,305,194	\$ 12,898,397	\$ 14,203,591
Discounted FNI @ 10%	\$ 1,019,719	\$ 7,212,392	\$ 8,232,111

	Probable		
	Developed		Total Probable
	Producing	Non-Producing	
<u>Net Remaining Reserves</u>			
Oil/Condensate – Barrels	3,182	30,269	33,451
Plant Products – Barrels	386	3,379	3,765
Gas – MMCF	6	50	56

	Possible			
	Developed		Undeveloped	Total Possible
	Producing	Non-Producing		
<u>Net Remaining Reserves</u>				
Oil/Condensate – Barrels	3,182	13,234	9,858	26,274
Plant Products – Barrels	386	1,565	1,154	3,105
Gas – MMCF	6	23	17	46

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. In this report, the revenues, deductions, and income data are expressed as U.S. dollars.

The estimates of the proved reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and

Reserves Software, a copyrighted program of Halliburton. The program was used 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 summarized. Furthermore, oneline 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 deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, transportation costs (incorporated as other costs in the cash flow projections) 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 89 percent and gas reserves account for the remaining 11 percent of total future gross revenue from proved reserves.

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

Discount Rate Percent	Discounted Future Net Income As of December 31, 2017
	Total Proved
5	\$10,623,071
15	\$6,585,531
20	\$5,412,894
25	\$4,550,551

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, probable and possible 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 under the attachment entitled “Petroleum Reserves Status Definitions and Guidelines” in this report. The proved, probable and possible developed 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 proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as 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.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that

the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. 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. At Apache's request, this report addresses the proved, probable and possible reserves attributable to the properties evaluated herein.

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 SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered." Probable reserves are "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." Possible reserves are "those additional reserves which are less certain to be recovered than probable reserves" and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

Reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible reserves included in this report are estimates only and should not be construed as being exact quantities. In the case of the proved reserves presented herein, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Apache's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved, probable and possible reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

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 liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved, probable and possible reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 95 percent of the proved, probable and possible producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis and/or material balance which utilized extrapolations of historical production and pressure data available through November 2017 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Apache or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 5 percent of the producing reserves were estimated by the volumetric method, analogy, or a combination of methods. These methods were used 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.

Approximately 100 percent of the proved, probable and possible developed non-producing and undeveloped reserves included herein were estimated by the volumetric method or analogy. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Apache or which we have obtained from public data sources that were available through November 2017. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved, probable and possible 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, probable and possible reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. 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 increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Apache has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, and probable and possible production, 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, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, 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 furnished by Apache. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved, probable and possible reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. 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.

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. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Apache. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of 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.

Apache furnished us with the above mentioned average prices in effect on December 31, 2017. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the proved future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Apache. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total proved future gross revenue before production taxes and the total proved net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	\$51.34/Bbl	\$56.27/Bbl
	NGLs	Mt. Belvieu Non-Tet Propane	\$31.82/Bbl	\$33.78/Bbl
	Gas	Henry Hub	\$2.98/MMBTU	\$2.92/MCF

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 were furnished by Apache and 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. 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. Transportation costs are included as deductions and incorporated as other costs. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Apache. 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 development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. 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.

The proved, probable and possible developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Apache’s plans to develop these reserves as of December 31, 2017. The implementation of Apache’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Apache’s management. As the result of our inquiries during the course of preparing this report, Apache has informed us that the development activities included herein have been subjected to and received the internal approvals required by Apache’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Apache. Additionally, Apache has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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 since 1937. 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 privately-owned or 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 financial 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 results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Terms of Usage

The results of our third party study, presented in report form herein, were 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/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPE License No. 107652

Senior Vice President
[SEAL]

AAP (FWZ)/pl

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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. Ali A. Porbandarwala was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Porbandarwala, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2008, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Porbandarwala served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Porbandarwala's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Porbandarwala earned a Bachelor of Science degree in Chemical Engineering from The University of Kansas in 2001 and a Masters in Business Administration from The University of Texas at Austin in 2007 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers as the Program Chair for the Houston chapter.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Porbandarwala fulfills. As part of his 2017 continuing education hours, Mr. Porbandarwala attended 25 hours of formalized training including the 2017 RSC Reserves Conference and/or various professional society presentations specifically 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.

Based on his educational background, professional training and more than 9 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Porbandarwala has attained the professional qualifications as 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 (SEC) 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 for 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 (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

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. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. 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 SEC. 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 SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only 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, natural gas 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 may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(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 §210.4-10(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.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(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.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

Probable reserves. *Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.*

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion.

Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

PETROLEUM 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. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(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 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 §210.4-10(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.*