APACHE CORP
Form 10-K
March 01, 2019
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
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 1-4300
APACHE CORPORATION
(Exact name of registrant as specified in its charter)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	New York Stock Exchange, Chicago Stock Exchange and NASDAQ Global Select Market
7.75% Notes Due 2029	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.625 par value
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] 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 [X]
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 [X] No [ ]
Indicate by check mark whether the registrant has submitted electronically, 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 [X] No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. [X]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ] Emerging growth company [ ]
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 [X]

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2018	$17,879,965,309
Number of shares of registrant's common stock outstanding as of January 31, 2019	375,405,587

Documents Incorporated By Reference

Portions of registrant's proxy statement relating to registrant's 2019 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

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DESCRIPTION

FORWARD-LOOKING STATEMENTS AND RISK

This Annual Report on Form 10-K 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, 2018, 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 “conti 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;
- our commodity hedging arrangements;
- the supply and demand for oil, natural gas, NGLs, and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the availability of goods and services;
- legislative, regulatory, or policy changes;
- terrorism or cyber attacks;
- occurrence of property acquisitions or divestitures;
- the integration of acquisitions;
- the securities or capital markets and related risks such as general credit, liquidity, market, and interest-rate risks; and
- other factors disclosed under Items 1 and 2—Business and Properties—Estimated Proved Reserves and Future Net Cash Flows, Item 1A—Risk Factors, Item 7—Management’s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A—Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this Form 10-K.

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

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

"3-D" means three-dimensional.
"4-D" means four-dimensional.
"b/d" means barrels of oil or natural gas liquids per day.
"bbl" or "bbls" means barrel or barrels of oil or natural gas liquids.
"bcf" means billion cubic feet of natural gas.
"boe" means barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.
"boe/d" means boe per day.
"Btu" means a British thermal unit, a measure of heating value.
"Liquids" means oil and natural gas liquids.
"LNG" means liquefied natural gas.
"Mb/d" means Mbbls per day.
"Mbbls" means thousand barrels of oil or natural gas liquids.
"Mboe" means thousand boe.
"Mboe/d" means Mboe per day.
"Mcf" means thousand cubic feet of natural gas.
"Mcf/d" means Mcf per day.
"MMbbls" means million barrels of oil or natural gas liquids.
"MMboe" means million boe.
"MMBtu" means million Btu.
"MMBtu/d" means MMBtu per day.
"MMcf" means million cubic feet of natural gas.
"MMcf/d" means MMcf per day.
"NGL" or "NGLs" means natural gas liquids, which are expressed in barrels.
"NYMEX" means New York Mercantile Exchange.
"oil" includes crude oil and condensate.
"PUD" means proved undeveloped.
"SEC" means United States Securities and Exchange Commission.
"Tcf" means trillion cubic feet of natural gas.
"U.K." means United Kingdom.
"U.S." means United States.

References to "Apache," the "Company," "we," "us," and "our" include Apache Corporation and its consolidated subsidiaries unless otherwise specifically stated.

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

PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

GENERAL

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. Apache currently has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). Apache also has exploration interests in Suriname that may, over time, result in a reportable discovery and development opportunity.

Our common stock, par value $0.625 per share, has been listed on the New York Stock Exchange (NYSE) since 1969, on the Chicago Stock Exchange (CHX) since 1960, and on the NASDAQ Global Select Market (NASDAQ) since 2004. Through our website, www.apachecorp.com, you can access, free of charge, electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance (including our Code of Business Conduct and Ethics and Apache's Corporate Governance Principles), and documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. Included in our annual and quarterly reports are the certifications of our principal executive officer and our principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. You may also request printed copies of our corporate charter, bylaws, committee charters, or other governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Our reports filed with the SEC are made available on its website at www.sec.gov. From time to time, we also post announcements, updates, and investor information on our website in addition to copies of all recent press releases. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Properties to which we refer in this document may be held by subsidiaries of Apache Corporation.

BUSINESS STRATEGY

Our VISION is to be the premier exploration and production company, contributing to global progress by helping meet the world's energy needs.

Our MISSION is to grow in an innovative, safe, environmentally responsible, and profitable manner for the long-term benefit of our stakeholders.

Our STRATEGY is to take a differentiated approach to the exploration and production of cost-advantaged hydrocarbons through innovation, technology, optimization, continuous improvement, and relentless focus on costs to deliver top-tier, long-term returns.

Rigorous management of the Company's asset portfolio plays a key role in optimizing shareholder value over the long term. Over the past several years, Apache has entered into a series of transactions that have upgraded its portfolio of assets, enhanced its capital allocation process to further optimize investment returns, and increased focus on internally generated exploration with full-cycle, returns-focused growth. These efforts included the monetization of certain non-strategic assets; including exiting operations in Canada and Australia, divesting of its interest in the Scottish Area Gas Evacuation (SAGE) system and pipeline in the North Sea, and selling other non-core leasehold and asset positions. The Company made strategic decisions to allocate the proceeds of these divestitures to more impactful development opportunities, including development of our Alpine High discovery in the Delaware Basin. We now have a diversified portfolio that features strong free cash flow generating assets in Egypt and the North Sea, which benefit from premium Brent crude oil pricing, and top-tier assets in the Permian Basin, the combination of which are the Company's foundation for returns-focused growth.

Additionally, in November 2018 the Company completed a transaction with Kayne Anderson Acquisition Corp. (KAAC) and its then wholly-owned subsidiary Altus Midstream LP (collectively, Altus) to create a publicly traded, pure-play, Permian Basin to Gulf Coast midstream C-corporation anchored by Apache's gathering, processing, and transmission assets at Alpine High. Subsequent to the transaction, KAAC was renamed to Altus Midstream Company (ALTM). This strategic transaction facilitates funding the capital intensive midstream infrastructure and enhances the allocation of Apache's capital to further development of the vast Alpine High upstream resource base, while maintaining control and a significant stake in the contributed assets.

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For a more in-depth discussion of the Company's 2018 results, divestitures, strategy, 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.

BUSINESS OVERVIEW

Subsequent to the Altus transaction, Apache management has established a new reporting segment for its Altus midstream business separate from upstream oil and gas development activities in the U.S. The following business overviews further describe the operations and activities for the Company's exploration and production properties and Altus midstream properties.

Exploration and Production Properties and Activities

Apache has exploration and production operations in three geographic areas: the U.S., Egypt, and the North Sea. Apache also has exploration interests in Suriname that may, over time, result in a reportable discovery and development opportunity.

The following table sets out a brief comparative summary of certain key 2018 data for each of Apache's operating areas. Additional data and discussion is provided in Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

	Production	Percentage of Total Production		Production Revenue	Year-End Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves		Gross Wells Drilled	Gross Productive Wells Drilled
	(In MMboe)			(In millions)	(In MMboe)				
United States	95.3	56	%	$ 3,279	892	72	%	335	327
Egypt[1]	54.4	32		2,748	205	17		115	99
North Sea[2]	20.3	12		1,321	137	11		10	9
Total	170.0	100	%	$ 7,348	1,234	100	%	460	435

(1) Apache's operations in Egypt, excluding a one-third noncontrolling interest, contributed 24 percent of 2018 production and accounted for 12 percent of year-end estimated proved reserves.

(2) Sales volumes from the North Sea for 2018 were 20.3 MMboe. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

United States

In 2018, Apache's U.S. operations contributed approximately 56 percent of production and 72 percent of estimated year-end proved reserves. Apache has access to significant liquid hydrocarbons across its 6.5 million gross acres in the U.S., 71 percent of which are undeveloped.

In the U.S., Apache has two onshore regions:

- The Permian region located in west Texas and New Mexico includes the Permian sub-basins: the Midland Basin, Central Basin Platform/Northwest Shelf, and Delaware Basin. Examples of shale plays within this region include the Woodford, Barnett, Pennsylvanian, Cline, Wolfcamp, Bone Spring, and Spraberry.
- The Midcontinent/Gulf Coast region includes the Granite Wash, Tonkawa, Marmaton, Cleveland, and other formations of the western Anadarko Basin, the Canyon Lime formation in the Texas panhandle, the Woodford-SCOOP and Stack plays located in central Oklahoma, and the Eagle Ford shale in east Texas.

Apache also has one offshore region in North America, the Gulf of Mexico region, which consists of both shallow and deep water exploration and production activities.

Permian Region The Permian region is one of Apache's core growth areas. Highlights of the Company's operations in the region include:

- Over 2.9 million gross acres with exposure to numerous plays focused primarily in the Midland Basin, the Central Basin Platform/Northwest Shelf, and the Delaware Basin.
- Estimated proved reserves of 770 MMboe at year-end 2018, representing 62 percent of the Company's worldwide proved reserves.

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- Annual production of 210.9 Mboe/d increased 34 percent from 2017. Fourth-quarter 2018 production increased 6 percent from the prior sequential quarter and 33 percent from the fourth quarter of 2017, a reflection of the success of the Midland Basin drilling program and the continued production ramp up at Alpine High, which first came online in May 2017.
- In 2018, the Permian region averaged 17 rigs and drilled or participated in 284 wells, 238 of which were horizontal, with a 98 percent success rate.

In late 2016, Apache announced the discovery of a significant new resource play, “Alpine High.” Apache’s Alpine High acreage lies in the southern portion of the Delaware Basin, primarily in Reeves County, Texas. Apache has identified over 3,500 economic drilling locations in a wet gas play and over 1,000 locations in a dry gas play at Alpine High. Over the past year, the Company focused on transitioning to full-field development of the Alpine High play, optimizing spacing, patterns, and completions and building efficiencies to reduce drilling and lifting costs. During 2018, Apache drilled 100 wells at Alpine High with a 96 percent success rate, including many concept test wells drilled to verify its understanding of the play. Using data collected from strategic testing and delineation drilling, the Company is now optimizing wells drilled in Alpine High and focusing on economic rich gas development in 2019. Combined with multi-well pad drilling and revenue uplift expected from oil and NGLs present in the wet gas play, Alpine High is anticipated to generate strong cash margins and a competitive recycle ratio when compared to other Permian operations.

In addition to activity in Alpine High, the Permian region drilled or participated in 184 wells in 2018, with a 98 percent success rate.

Apache plans to continue focusing a majority of its capital activity in the Permian region during 2019, balancing capital investments between its larger development project at Alpine High and focused exploration and development programs on other core assets in its Permian region. During 2019, the Company expects to average approximately 12 drilling rigs in the Permian region, which includes five rigs at Alpine High largely focused on development drilling.

Midcontinent/Gulf Coast Region Apache’s Midcontinent/Gulf Coast region includes 1.7 million gross acres and over 3,000 producing wells primarily in western Oklahoma, the Texas Panhandle and the Eagle Ford shale in east Texas. In 2018, the region accounted for 10 percent of the Company’s production and approximately 9 percent of the Company’s year-end estimated proved reserves.

In 2018, Apache drilled 15 operated wells running a targeted program in the Woodford-SCOOP play and the Canyon Lime formation, which were all productive. In 2019, the region will continue its focus on high-grading acreage, building its inventory of future drilling locations, and pursuing potential divestiture opportunities for non-core positions.

Gulf of Mexico Region The Gulf of Mexico region comprises assets in the offshore waters of the Gulf of Mexico and onshore Louisiana. In addition to its interest in several deepwater exploration and development offshore leases, when the Company sold in 2013 substantially all of its offshore assets in water depths less than 1,000 feet, it retained a 50 percent ownership interest in all exploration blocks and in horizons below production in development blocks, and access to existing infrastructure. Apache’s offshore technical teams continue to focus on evaluating subsalt and other deeper exploration opportunities in water depths less than 1,000 feet, which have been relatively untested by the industry, where high-potential deep hydrocarbon plays may exist. During 2018, Apache’s Gulf of Mexico region participated in 4 non-operated exploratory wells with an average 26 percent working interest, of which three were successful. The region contributed 5.1 Mboe/d to the Company’s total production for the year.

U.S. Marketing In general, most of the Company’s U.S. natural gas production is sold at either monthly or daily index-based prices. The tenor of the Company’s sales contracts span from daily to multi-year transactions. Natural gas is sold to a variety of customers that include local distribution, utility, and midstream companies as well as end-users, marketers, and integrated major oil companies. Apache strives to maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk. Beginning in 2017, Apache began selling gas that was consumed in Mexico and to LNG export facilities in the U.S.

Apache primarily markets its U.S. crude oil production to integrated major oil companies, marketing and transportation companies, and refiners based on a West Texas Intermediate (WTI) price or other regional pricing indices (e.g. LLS, WTS, or Midland), adjusted for quality, transportation, and a market-reflective differential.

Apache's objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices. Also, from time to time, the Company will enter into physical term sales contracts. These term contracts typically have a firm transportation commitment and often provide for the higher of prevailing market prices from multiple market hubs.

Apache's U.S. NGL production is sold under contracts with prices based on local supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Apache has contracted takeaway capacity (through a combination of volume commitments and acreage/plant dedications) in the Permian Basin on the following third-party pipelines that are currently under construction and expected to be in operation in 2019 and 2020 as further described under "Altus: Midstream Properties and Activities" below:

(i) 550,000 dekatherms per day of residue gas for a 10-year term on the Gulf Coast Express Pipeline;

(ii) 500,000 dekatherms per day of residue gas for a 10-year term on the Permian Highway Pipeline;

(iii) an acreage dedication of crude oil produced from Alpine High up to 75 MBbl/d of crude oil for a 10-year term on the EPIC Crude pipeline;

(iv) an acreage dedication to transport NGLs produced from Alpine High to Waha for a 10-year term on the Salt Creek NGL Pipeline; and

(v) an acreage dedication for a 10-year term on Enterprise Products' Shin Oak NGL Pipeline to transport up to 205 MBbl/d of Alpine High produced NGLs from the Salt Creek NGL Pipeline terminus in Waha to Mont Belvieu.

This takeaway capacity will allow greater flexibility and market optionality for Apache's Permian Basin production, including increasing volumes from Alpine High.

International

In 2018, international assets contributed 44 percent of Apache's production and 55 percent of oil and gas revenues. Approximately 28 percent of estimated proved reserves at year-end were located outside the U.S.

Apache has two international regions:

- The Egypt region includes onshore conventional assets in Egypt's Western Desert.
- The North Sea region includes offshore assets based in the United Kingdom.

The Company also has an offshore exploration program in Suriname.

Egypt Apache has 23 years of exploration, development and operations experience in Egypt and is one of the largest acreage holders in Egypt's Western Desert. At year-end 2018, the Company held 6.2 million gross acres in 25 separate concessions. Development leases within concessions currently have expiration dates ranging from 3 to 20 years, with extensions possible for additional commercial discoveries or on a negotiated basis. Approximately 73 percent of the Company's gross acreage in Egypt is undeveloped, providing us with considerable exploration and development opportunities for the future.

Apache's Egypt operations are conducted pursuant to production sharing contracts (PSCs). Under the terms of the Company's PSCs, the contractor partner (Contractor) bears the risk and cost of exploration, development, and production activities. In return, if exploration is successful, the Contractor receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of production after cost recovery. Additionally, the Contractor's income taxes, which remain the liability of the Contractor under domestic law, are paid by Egyptian General Petroleum Corporation (EGPC) on behalf of the Contractor out of EGPC's production entitlement. Income taxes paid to the Arab Republic of Egypt on behalf of the Contractor are recognized as oil and gas sales revenue and income tax expense and reflected as production and estimated reserves. Because Contractor cost recovery entitlement and income taxes paid on its behalf are determined as a monetary amount, the quantities of production entitlement and estimated reserves attributable to these monetary amounts will fluctuate with commodity prices. In addition, because the Contractor income taxes are paid by EGPC, the amount of the income tax has no economic impact on Apache's Egypt operations despite impacting Apache's production and reserves.

The Company's estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country's share of reserves. In addition, Sinopec International Petroleum Exploration and Production Corporation (Sinopec) holds a one-third minority participation interest in Apache's oil and gas operations in Egypt. The Egypt region, including the one-third noncontrolling interest, contributed 32 percent of 2018 production and 17 percent of year-end estimated proved reserves. Excluding the noncontrolling interest, Egypt contributed 24 percent of 2018 production and 12 percent of year-end estimated proved reserves.

In 2018, the region drilled 70 development and 45 exploration wells. Approximately 67 percent of the exploration wells were successful, further expanding Apache's presence in the westernmost concessions and unlocking additional opportunities in existing plays. A key component of the region's success has been the ability to acquire and evaluate 3-D seismic surveys that enable Apache's technical teams to consistently high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic formations. During 2017 and early 2018, Apache began shooting high-resolution 3-D seismic surveys in the West Kalabsha concession, the first of its kind in the Western Desert. The Company has completed seismic surveys covering over 1.25 million acres to date and will ultimately expand the shoot to cover the majority of its acreage in Egypt. The program will provide newer vintage, higher resolution imaging of the substrata across Apache's Western Desert position, allowing the Company to build and high-grade its drilling inventory.

Heading into 2019, the region plans to advance its large-scale seismic shoot and continue to build its prospect inventory. With recent acreage positions added over the past 18 months, the Egypt region will also drill wells in each of the new concession areas, thereby laying a foundation for potential growth.

Egypt Marketing Apache's natural gas production in Egypt is sold to EGPC primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content.

Crude oil production is sold to third parties in the export market or to EGPC when called upon to supply domestic demand. Oil production sold to third parties is exported from or sold at one of two terminals on the northern coast of Egypt. Oil production sold to EGPC is sold at prices equivalent to the export market.

North Sea Apache has interests in approximately 430,000 gross acres in the U.K. North Sea. The region contributed 12 percent of Apache's 2018 production and approximately 11 percent of year-end estimated proved reserves.

Apache entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (Forties). Since acquiring Forties, Apache has actively invested in the region and has established a large inventory of drilling prospects through successful exploration programs and the interpretation of 4-D seismic. Building upon its success in Forties, in 2011 Apache acquired Mobil North Sea Limited, providing the region with additional exploration and development opportunities across numerous fields, including operated interests in the Beryl, Ness, Nevis, Nevis South, Skene, and Buckland fields and a non-operated interest in the Maclure field. Apache also has a non-operated interest in the Nelson field acquired in 2011. The Beryl field, which is a geologically complex area with multiple fields and stacked pay potential, provides for significant exploration opportunity. The North Sea region plays a strategic role in Apache's portfolio by providing competitive investment opportunities and potential reserve upside with high-impact exploration potential.

During 2018, the region drilled 8 development wells with a 100 percent success rate: four at Forties, three at Beryl and one at Callater. In addition, the region drilled two exploration wells, one of which was unsuccessful.

Apache initiated production from its Garten development in the Beryl area in late November 2018, less than eight months after being drilled in March 2018. The discovery well at Garten encountered 778 feet of net oil pay in stacked, high-quality, Jurassic-aged sandstone reservoirs. Two lower zones were also successfully tested, and all three zones will ultimately be commingled to maximize recovery. Apache has a 100 percent working interest in the Garten development.

The Company plans to maintain its activity set in the North Sea for 2019, with two platform rigs (one at Forties and one at Beryl) and a semi-submersible rig.

North Sea Marketing Apache has traditionally sold its North Sea crude oil under term contracts, with a market-based index price plus a premium, which reflects the higher market value for term arrangements.

Natural gas from the Beryl field is processed through the SAGE gas plant, which Apache divested to Ancala Midstream Acquisitions Limited in late 2017. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The condensate mix from the SAGE plant is processed further downstream. The split streams of propane and butane are sold on a monthly entitlement basis, and condensate is sold on a spot basis at the Braefoot Bay terminal using index pricing less transportation.

Other Exploration

New Ventures   Apache's global New Ventures team provides exposure to new growth opportunities by looking outside of the Company's traditional core areas and targeting higher-risk, higher-reward exploration opportunities located in frontier basins as well as new plays in more mature basins. Apache drilled an exploration well in the first half of 2017 in offshore Suriname, which was unsuccessful, and drilled no additional wells in Suriname during 2018. Plans for 2019 include drilling one well on Block 58 in offshore Suriname.

Delivery Commitments

Over the past two years, the Company has entered into several long-term delivery commitments primarily related to the continued development of Alpine High. These fixed-minimum sales volume commitments coincide with recent firm transportation agreements and takeaway capacity arrangements with third parties in the Permian Basin. The sales commitments require Apache to deliver an average of 260 Bcf of natural gas per year for the period from 2019 through 2029 at variable, market-based pricing.

Apache expects to fulfill the majority of these delivery commitments with production from its proved reserves. Any remaining commitments may be fulfilled with production from continued development and/or spot market purchases as necessary. The Company has not experienced any significant constraints in satisfying the committed quantities required by its sales commitments.

Drilling Statistics

Worldwide in 2018, Apache participated in drilling 460 gross wells, with 435 (95 percent) completed as producers. Historically, Apache's drilling activities in the U.S. have generally concentrated on exploitation and extension of existing producing fields rather than exploration. As a general matter, Apache's operations outside of the U.S. focus on a mix of exploration and development wells. In addition to Apache's completed wells, at year-end a number of wells had not yet reached completion: 125 gross (111.2 net) in the U.S., 16 gross (15.2 net) in Egypt, and 3 gross (2.1 net) in the North Sea.

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

	Net Exploratory			Net Development			Total Net Wells		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
2018									
United States	47.6	5.3	52.9	188.9	2.0	190.9	236.5	7.3	243.8
Egypt	28.2	12.5	40.7	57.9	0.5	58.4	86.1	13.0	99.1
North Sea	1.0	0.5	1.5	6.3	—	6.3	7.3	0.5	7.8
Total	76.8	18.3	95.1	253.1	2.5	255.6	329.9	20.8	350.7
2017									
United States	42.9	4.3	47.2	101.5	1.0	102.5	144.4	5.3	149.7
Canada	—	1.0	1.0	0.2	—	0.2	0.2	1.0	1.2
Egypt	13.7	12.0	25.7	59.3	3.0	62.3	73.0	15.0	88.0
North Sea	0.6	1.9	2.5	6.4	1.0	7.4	7.0	2.9	9.9
Other International	—	0.5	0.5	—	—	—	—	0.5	0.5
Total	57.2	19.7	76.9	167.4	5.0	172.4	224.6	24.7	249.3
2016									
United States	18.9	5.0	23.9	79.5	1.9	81.4	98.4	6.9	105.3
Canada	—	2.0	2.0	10.2	—	10.2	10.2	2.0	12.2
Egypt	7.3	5.1	12.4	40.5	1.0	41.5	47.8	6.1	53.9
North Sea	—	0.9	0.9	8.2	1.6	9.8	8.2	2.5	10.7
Total	26.2	13.0	39.2	138.4	4.5	142.9	164.6	17.5	182.1

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Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which the Company had an interest as of December 31, 2018, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	13,240	8,615	3,110	1,610	16,350	10,225
Egypt	1,200	1,130	125	120	1,325	1,250
North Sea	155	115	20	10	175	125
Total	14,595	9,860	3,255	1,740	17,850	11,600
Domestic	13,240	8,615	3,110	1,610	16,350	10,225
Foreign	1,355	1,245	145	130	1,500	1,375
Total	14,595	9,860	3,255	1,740	17,850	11,600

Gross natural gas and crude oil wells include 575 wells with multiple completions.

Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGL, and gas production volumes, average lease operating costs per boe (including transportation costs but excluding severance and other taxes), and average sales prices for each of the countries where the Company has operations:

	Production			Average Lease Operating	Average Sales Price		
Year Ended December 31,	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Cost per Boe	Oil (Per bbl)	NGL (Per bbl)	Gas (Per Mcf)
2018							
United States	38.3	21.0	216.5	$ 10.01	$59.36	$26.28	$2.12
Egypt(1)	34.2	0.3	119.3	8.71	70.09	39.17	2.84
North Sea(2)	17.1	0.4	16.6	18.92	69.02	45.84	7.33
Total	89.6	21.7	352.4	10.66	65.30	26.87	2.61
2017							
United States	33.4	17.8	143.9	$ 8.92	$48.40	$16.14	$2.56
Canada(3)	2.4	1.0	48.0	12.01	45.25	16.39	2.17
Egypt(1)	35.5	0.3	141.0	6.85	53.57	36.79	2.80
North Sea(2)	17.9	0.4	16.6	17.21	53.81	36.22	5.54
Total	89.2	19.5	349.5	9.45	51.46	16.90	2.74
2016							
United States	38.0	19.8	145.0	$ 7.72	$39.43	$9.28	$2.17
Canada	4.8	2.1	88.8	11.52	37.62	8.15	1.64
Egypt(1)	37.9	0.4	143.4	7.86	43.66	28.68	2.71
North Sea(2)	20.0	0.6	26.3	13.14	42.93	24.20	4.51
Total	100.7	22.9	403.5	8.90	41.63	9.92	2.40

(1) Includes production volumes attributable to a one-third noncontrolling interest in Egypt.

(2) Sales volumes from the North Sea for 2018, 2017, and 2016 were 20.3 MMboe, 21.2 MMboe, and 24.5 MMboe, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

(3) During the third quarter of 2017, Apache finalized the sale and complete exit of its Canadian operations.

Gross and Net Undeveloped and Developed Acreage

The following table sets out Apache's gross and net acreage position as of December 31, 2018, in each country where the Company has operations:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)			
United States	4,580	2,260	1,904	1,093
Egypt	4,480	4,088	1,686	1,609
North Sea	245	225	186	135
Other International	2,308	1,831	—	—
Total	11,613	8,404	3,776	2,837

As of December 31, 2018, 41 percent of U.S. net undeveloped acreage was held by production.

As of December 31, 2018, Apache had 796,000 net undeveloped acres scheduled to expire by year-end 2019 if production is not established or Apache takes no other action to extend the terms. Additionally, Apache has 2.1 million and 1.5 million net undeveloped acres set to expire in 2020 and 2021, respectively. The Company strives to extend the terms of many of these licenses and concession areas through operational or administrative actions, but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third parties, including governments.

Exploration concessions in Apache's Egypt region comprise a significant portion of Apache's net undeveloped acreage expiring over the next three years. Apache has 632,000 net undeveloped acres expiring in Egypt during 2019. Approximately 98,000 and 1.3 million net undeveloped acres are set to expire in 2020 and 2021, respectively. There were no reserves recorded on this undeveloped acreage. Apache will continue to pursue acreage extensions and access to new concessions in areas in which it believes exploration opportunities exist.

Additionally, Apache has exploration interests in Suriname consisting of 1.8 million net undeveloped acres in two offshore blocks set to expire in 2020. Apache has acquired 3-D seismic surveys over all the acreage. No reserves have been booked on this undeveloped acreage.

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. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods. The Company reports all estimated proved reserves held under production-sharing arrangements utilizing the "economic interest" method, which excludes the host country's share of reserves.

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 that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating its proved reserves, Apache uses several different traditional methods that can be classified in three general categories: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy with similar properties. Apache will, at times, utilize additional technical analysis, such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods, to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of the Company's reserve estimates.

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.

The following table shows proved oil, NGL, and gas reserves as of December 31, 2018, based on average commodity prices in effect on the first day of each month in 2018, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. This table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a ratio of 6 Mcf to 1 bbl. This ratio is not reflective of the current price ratio between the two products.

	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Total (MMboe)
Proved Developed:				
United States	300	198	1,627	769
Egypt[(1)]	110	1	476	190
North Sea	105	1	95	122
Total Proved Developed	515	200	2,198	1,081
Proved Undeveloped:				
United States	45	33	267	123
Egypt[(1)]	10	—	33	15
North Sea	11	1	16	15
Total Proved Undeveloped	66	34	316	153
TOTAL PROVED	581	234	2,514	1,234

(1) Includes total proved developed and total proved undeveloped reserves of 63 MMboe and 5 MMboe, respectively, attributable to a one-third noncontrolling interest in Egypt.

As of December 31, 2018, Apache had total estimated proved reserves of 581 MMbbls of crude oil, 234 MMbbls of NGLs, and 2.5 Tcf of natural gas. Combined, these total estimated proved reserves are the volume equivalent of 1.2 billion barrels of oil or 7.4 Tcf of natural gas, of which oil represents 47 percent. As of December 31, 2018, the Company's proved developed reserves totaled 1,081 MMboe and estimated PUD reserves totaled 153 MMboe, or approximately 12 percent of worldwide total proved reserves. Apache has elected not to disclose probable or possible reserves in this filing.

During 2018, Apache added 303 MMboe of proved reserves through exploration and development activity, partially offset by combined downward revisions of previously estimated reserves of 73 MMboe. Engineering and performance downward revisions accounted for 44 MMboe, changes in product prices accounted for 24 MMboe, and interest revisions accounted for 5 MMboe.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2018, 2017, and 2016, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 15—Supplemental Oil and Gas Disclosures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. Estimated future net cash flows were calculated using a discount rate of 10 percent per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

Proved Undeveloped Reserves

The Company’s total estimated PUD reserves of 153 MMboe as of December 31, 2018, increased by 2 MMboe from 151 MMboe of PUD reserves reported at the end of 2017. During the year, Apache converted 76 MMboe of PUD reserves to proved developed reserves through development drilling activity. In the U.S., Apache converted 57 MMboe, with the remaining 19 MMboe in Apache’s international areas. Apache did not sell or acquire any PUD reserves during the year. Apache added 128 MMboe of new PUD reserves through extensions and discoveries. Apache recognized a 10 MMboe downward engineering revision in proved undeveloped reserves during the year. Other downward revisions included 24 MMboe associated with product prices, 11 MMboe associated with revised development plans, and 5 MMboe associated with interest revisions.

During the year, a total of approximately $446 million was spent on projects associated with reserves that were carried as PUD reserves at the end of 2017. A portion of Apache’s costs incurred each year relate to development projects that will be converted to proved developed reserves in future years. Apache spent approximately $322 million on PUD reserve development activity in the U.S. and $124 million in the international areas. As of December 31, 2018, Apache had no material amounts of proved undeveloped reserves scheduled to be developed beyond five years from initial disclosure.

Preparation of Oil and Gas Reserve Information

Apache’s reported reserves are reasonably certain estimates which, by their very nature, are subject to revision. These estimates are reviewed throughout the year and revised either upward or downward, as warranted.

Apache’s proved reserves are estimated at the property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers that is independent of the operating groups. These engineers interact with engineering and geoscience personnel in each of Apache’s operating areas and with accounting and marketing employees to obtain the necessary data for projecting future production, costs, net revenues, and ultimate recoverable reserves. All relevant data is compiled in a computer database application, to which only authorized personnel are given security access rights consistent with their assigned job function. Reserves are reviewed internally with senior management and presented to Apache’s Board of Directors in summary form on a quarterly basis. Annually, each property is reviewed in detail by our corporate and operating region engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable.

Apache’s Executive Vice President of Planning, Reserves and Fundamentals is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating any reserves audits conducted by a third-party engineering firm. He has Bachelor of Science and Master of Science degrees in Petroleum Engineering and over 30 years of experience in the energy industry and energy sector of the banking industry. The Executive Vice President of Planning, Reserves and Fundamentals reports directly to our Chief Executive Officer.

The estimate of reserves disclosed in this Annual Report on Form 10-K is prepared by the Company’s internal staff, and the Company is responsible for the adequacy and accuracy of those estimates. However, the Company engages Ryder Scott Company, L.P. Petroleum Consultants (Ryder Scott) to review our processes and the reasonableness of our estimates of proved hydrocarbon liquid and gas reserves. The Company selects the properties for review by Ryder Scott based primarily on relative reserve value. The Company also considers other factors such as geographic location, new wells drilled during the year and reserves volume. During 2018, the properties selected for each country ranged from 84 to 91 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for over 88 percent of the reserves value of Apache’s international proved reserves and 95 percent of the reserves value of Apache’s new wells drilled worldwide. In addition, all fields containing five percent or more of the Company’s total proved reserves volume were included in Ryder Scott’s review. The review covered 83 percent of total proved reserves by volume.

Ryder Scott’s review for the years 2018, 2017, and 2016 covered 86, 92, and 92 percent, respectively, of the value and 83, 84, and 83 percent, respectively, of the volume of the Company’s worldwide estimated proved reserves. Ryder Scott’s 2018 review covered 82, 85, and 81 percent of the estimated proved reserve volume in the U.S., Egypt, and U.K., respectively.

Ryder Scott’s review of 2017 covered 84 percent of U.S., 85 percent of Egypt, and 81 percent of the U.K.’s total proved reserves.

Ryder Scott's review of 2016 covered 81 percent of U.S., 81 percent of Canada, 85 percent of Egypt, and 92 percent of the U.K.'s total proved reserves.
The Company has filed Ryder Scott's independent report as an exhibit to this Form 10-K.

According to Ryder Scott's opinion, based on their review, including the data, technical processes, and interpretations presented by Apache, the overall procedures and methodologies utilized by Apache in determining the proved reserves comply with the current SEC regulations, and the overall proved reserves for the reviewed properties as estimated by Apache are, in aggregate, reasonable within the established audit tolerance guidelines as set forth in the Society of Petroleum Engineers auditing standards.

Altus: Midstream Properties and Activities

In November 2018, Apache completed a previously announced transaction with KAAC and its then wholly-owned subsidiary Altus Midstream LP (collectively, Altus) to create a pure-play, Permian Basin to Gulf Coast midstream C-corporation anchored by Apache's gathering, processing, and transmission assets at Alpine High. Pursuant to the agreement, Apache contributed certain Alpine High midstream assets and options to acquire equity interests in five separate third-party pipeline projects to Altus Midstream LP and/or its subsidiaries. In exchange for the assets, Apache received economic voting and non-economic voting shares in KAAC and limited partner interests in Altus Midstream LP, representing an approximate 79 percent ownership interest in the combined entities. Upon closing, KAAC changed its name to Altus Midstream Company (ALTM).

Apache fully consolidates the assets and liabilities of Altus in its consolidated financial statements, with a corresponding noncontrolling interest reflected separately.

Altus owns, develops, and operates gas gathering, processing, and transmission assets in the Permian Basin of West Texas. Altus primarily generates revenue by providing fee based natural gas gathering, compression, processing, and transportation services for Apache's production from its Alpine High resource play. As of December 31, 2018, Altus's assets included approximately $1.2 billion of natural gas gathering, transmission, and processing infrastructure. This includes approximately 111 miles natural gas gathering pipelines, approximately 52 miles of residue-gas pipelines, and approximately 26 miles of NGL pipelines. Additionally, Altus owns five rich gas processing facilities consisting of approximately 77,000 horsepower with 380 MMcf/d of rich-gas processing capacity and two lean gas facilities consisting of 75,000 horsepower with 400 MMcf/d of lean-gas treating capacity. Other assets include an NGL truck loading terminal with six lease automatic custody transfer (LACT) units and eight NGL bullet tanks with 90,000 gallon capacity per tank.

Altus continues to invest in the development of its asset base. By the end of 2019, Altus has forecasted the completion of three cryogenic processing plants with combined nameplate capacity of approximately 600 MMcf/d. Additionally, Altus expects to add approximately 50 miles of gathering pipelines with expanded horsepower and compression capacity to service additional market outlets.

Joint Venture Pipeline Projects

Gulf Coast Express In December 2018, Altus Midstream LP exercised and closed its option with Kinder Morgan Pipeline LLC, thereby acquiring a 15 percent equity interest in the Gulf Coast Express Pipeline Project (GCX). GCX is a long-haul natural gas pipeline that, upon completion, is expected to have capacity of approximately 2.0 Bcf/d and will transport natural gas from the Waha area in northern Pecos County, Texas to the Agua Dulce Hub near the Texas Gulf Coast. GCX will be operated by Kinder Morgan Texas Pipeline LLC and is expected to be operational and in-service in the fourth quarter of 2019.

EPIC Crude In February 2019, Altus Midstream LP's subsidiary exercised its option with EPIC Pipeline LP to acquire a 15 percent equity interest in the EPIC crude oil pipeline. The transaction is anticipated to close in the first quarter of 2019. The pipeline is a long-haul crude oil pipeline that, upon completion, is expected to have an initial throughput capacity of approximately 590 MBbl/d from the Permian Basin to Corpus Christi, Texas. The EPIC crude pipeline will be operated by EPIC Consolidated Operations, LLC and is expected to be in service in the first quarter of 2020.

Pipeline Project Options

Altus Midstream LP and its subsidiaries also hold additional options to acquire equity interests that have not yet been exercised. These options facilitate participation in the following third-party pipeline projects that are expected to be placed into service in 2019 and 2020:

- Salt Creek NGL Pipeline;
- Shin Oak Pipeline; and
- Permian Highway Pipeline.

Salt Creek NGL Pipeline Altus Midstream LP's subsidiary has an option to acquire a 50 percent equity interest in the Salt Creek NGL Pipeline, an intra-basin NGL pipeline that, upon completion, is expected to be capable of transporting approximately 445 MBbl/d to the Waha area in northern Pecos County, Texas. The Salt Creek NGL Pipeline will be operated by ARM Midstream Management LLC and is expected to be operational and in service in the first quarter of 2019. Altus Midstream LP's subsidiary expects to exercise this option in the fourth quarter of 2019 or the first quarter of 2020.

Shin Oak Pipeline Altus Midstream LP's subsidiary has an option to acquire up to a 33 percent equity interest in the Shin Oak Pipeline, a long-haul NGL pipeline that, upon completion, is expected to be capable of transporting approximately 550 MBbl/d from northern Reeves County, Texas through the Waha area in northern Pecos County, Texas, and on to Mont Belvieu, Texas. The Shin Oak Pipeline will be operated by Enterprise Products Operating LLC and is expected to be operational and in service in the second quarter of 2019. Altus Midstream LP's subsidiary expects to exercise this option in the second half of 2019.

Permian Highway Pipeline Altus Midstream LP's subsidiary has an option to acquire an approximate 27 percent equity interest in the Permian Highway Pipeline, a long-haul natural gas pipeline that, upon completion, is expected to have capacity of approximately 2.1 Bcf/d and will transport natural gas from the Waha area in northern Pecos County, Texas to the Katy, Texas area with connections to U.S. Gulf Coast and Mexico markets. The Permian Highway Pipeline will be operated by Kinder Morgan Texas Pipeline LLC and is expected to be operational and in service during the fourth quarter of 2020. Altus Midstream LP's subsidiary expects to exercise this option in the second half of 2019.

MAJOR CUSTOMERS

For the years ended 2018, 2017, and 2016, the customers, including their subsidiaries, that represented more than 10 percent of the Company's worldwide oil and gas production revenues were as follows:

	For the Year Ended December 31,		
	2018	2017	2016
BP plc	17%	12%	9 %
China Petroleum & Chemical Corporation (Sinopec)	15%	16%	21%
Egyptian General Petroleum Corporation	10%	11%	12%

EMPLOYEES

On December 31, 2018, the Company had 3,420 employees.

OFFICES

Our principal executive offices are located at One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400. At year-end 2018, the Company maintained regional exploration and/or production offices in Midland, Texas; San Antonio, Texas; Houston, Texas; Cairo, Egypt; and Aberdeen, Scotland. Apache leases all of its primary office space. The current lease on our principal executive offices runs through December 31, 2024. The Company has an option to extend the lease through 2029. For information regarding the Company's obligations under its office leases, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Contractual Obligations and Note 9—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

TITLE TO INTERESTS

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

ADDITIONAL INFORMATION ABOUT APACHE

Response Plans and Available Resources

Apache and its wholly owned subsidiary, Apache Deepwater LLC (ADW), developed Oil Spill Response Plans (the Plans) for their respective Gulf of Mexico operations and offshore operations in the North Sea and Suriname. These plans ensure rapid and effective responses to spill events that may occur on such entities' operated properties. Annually, drills are conducted to measure and maintain the effectiveness of the Plans.

Apache is a member of Oil Spill Response Limited (OSRL), a large international oil spill response cooperative, which entitles any Apache entity worldwide to access OSRL's services. Apache also has a contract for global response resources and services with National Response Corporation (NRC). NRC is the world's largest commercial Oil Spill Response Organization and is the global leader in providing end-to-end environmental, industrial, and emergency response solutions with operating bases in 13 countries.

In the event of a spill in the Gulf of Mexico, Clean Gulf Associates (CGA) is the primary oil spill response association available to Apache and ADW. Both Apache and ADW are members of CGA, a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico. CGA was created to provide a means of effectively staging response equipment and providing immediate spill response for its member companies' operations in the Gulf of Mexico. In the event of a spill, CGA's equipment, which is positioned at various staging points around the Gulf, is ready to be mobilized.

Competitive Conditions

The oil and gas business is highly competitive in the exploration for and acquisitions of reserves, the acquisition of oil and gas leases, equipment and personnel required to find and produce reserves, and the gathering and marketing of oil, gas, and natural gas liquids. Our competitors include national oil companies, major integrated oil and gas companies, other independent oil and gas companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers.

Certain of our competitors may possess financial or other resources substantially larger than we possess or have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for leases or drilling rights. However, we believe our diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across three geographic areas, our balanced production mix between oil and gas, our management and incentive systems, and our experienced personnel give us a strong competitive position relative to many of our competitors who do not possess similar geographic and production diversity. Our global position provides a large inventory of geologic and geographic opportunities in the geographic areas in which we have producing operations to which we can reallocate capital investments in response to changes in commodity prices, local business environments, and markets. It also reduces the risk that we will be materially impacted by an event in a specific area or country.

Environmental Compliance

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

We have made and will continue to make expenditures in our efforts to comply with these requirements, which we believe are necessary business costs in the oil and gas industry. We have established policies for continuing compliance with environmental laws and regulations, including regulations applicable to our operations in all countries in which we do business. We have established operating procedures and training programs designed to limit the environmental impact of our field facilities and identify and comply with changes in existing laws and regulations. The costs incurred under these policies and procedures are inextricably connected to normal operating expenses such that we are unable to separate expenses related to environmental matters; however, we do not believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on our capital expenditures, earnings, or competitive position.

ITEM 1A. RISK FACTORS

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Additional risks relating to our securities may be included in the prospectuses for securities we issue in the future.

Crude oil, natural gas, and NGL price volatility could adversely affect our operating results and the price of our common stock.

Our revenues, operating results, and future rate of growth depend highly upon the prices we receive for our crude oil, natural gas, and NGL production. Historically, the markets for these commodities have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2018 ranged from a high of $76.41 per barrel to a low of $42.53 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2018 ranged from a high of $4.84 per MMBtu to a low of $2.55 per MMBtu. The market prices for crude oil, natural gas, and NGLs depend on factors beyond our control. These factors include demand, which fluctuates with changes in market and economic conditions, and other factors, including:

- worldwide and domestic supplies of crude oil, natural gas, and NGLs;
- actions taken by foreign oil and gas producing nations, including the Organization of the Petroleum Exporting Countries (OPEC);
- political conditions and events (including instability, changes in governments, or armed conflict) in oil and gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of imported foreign crude oil, natural gas, and NGLs;
- 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 2018, prices have remained significantly lower than levels seen in 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, natural gas, and NGLs 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, natural gas, and NGLs that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income, and cash flows;
- limiting our access to sources of capital, such as equity and long-term debt;
- reducing the carrying value of our oil and gas properties, resulting in additional non-cash impairments;
- reducing the carrying value of our gathering, transmission, and processing facilities, resulting in additional impairments; or
- reducing the carrying value of goodwill.

Our ability to sell crude oil, natural gas, or NGLs and/or receive market prices for these commodities may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.
A portion of our crude oil, natural gas, and NGL production in any region 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. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows.
Future economic conditions in the U.S. and certain international markets may materially adversely impact our 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 on our operating results. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our oil and gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.
Weather and climate may have a significant adverse impact on our revenues and production.
Demand for oil and 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 freezing temperatures, hurricanes in the Gulf of Mexico, or storms in the North Sea, 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 conditions, and not all such effects can be predicted, eliminated, or insured against.
Our operations involve a high degree of operational risk, particularly risk of personal injury, damage or loss of equipment, and environmental accidents.
Our operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil, natural gas, and NGLs, including:

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

Failure or loss of equipment, as the result of equipment malfunctions, cyberattacks, 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, fire at a location where our equipment and services are used, or ground 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 surface or ground 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 terrorist or cyberattack targeting systems and infrastructure used by us or others in the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, and production activities. We 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 our employees and third party partners, and conduct many of our activities. Unauthorized access to our digital technology could lead to operational disruption, data corruption, communication interruption, loss of intellectual property, loss of confidential and fiduciary data, and loss or corruption of reserves or other proprietary information. Strategic targets, such as energy-related assets, may be at greater risk of future terrorist attacks, environmental activist group activities, or cyberattacks than other targets in the United States. Also, external digital technologies control nearly all of the oil and gas distribution and refining systems in the United States and abroad, which are necessary to transport and market our production. A cyberattack 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. Any such terrorist attack, environmental activist group activity, or cyberattack that affects the Company or our customers, suppliers, or others with whom we do business could have a material adverse effect on our business, cause it to incur a material financial loss, subject it to possible legal claims and liability, and/or damage our reputation.

While we have experienced cyberattacks in the past, we have not suffered any material losses as a result of such attacks; however, there is no assurance that we will not suffer such losses in the future. Further, as cyberattacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyberattacks. In addition, cyberattacks against us or others in our industry could result in additional regulations, which could lead to increased regulatory compliance costs, insurance coverage cost, or capital expenditures. The Company cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

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

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

- our production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or
- an unexpected event materially impacts commodity prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds, and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit or financial markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We may also have exposure to financial institutions in the form of derivative transactions in connection with any hedges. We also have exposure to insurance companies in the form of claims under our policies. In addition, if any lender under our credit facilities is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facilities.

We are exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. This risk of counterparty non-performance is of particular concern given the recent volatility of the financial markets and significant decline in commodity prices, which could lead to sudden changes in a counterparty's liquidity and impair its ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge providers 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 to us by the distressed entity or entities. During periods of falling commodity prices, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

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

Concerns about global economic conditions and the volatility of oil, natural gas, and NGL prices have had a significant adverse impact on the oil and gas industry. We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas, and NGLs to a variety of purchasers. As operator, we pay expenses and bill our non-operating partners for their respective shares of costs. As a result of current economic conditions and the severe decline in commodity prices, some of our customers and non-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 non-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 customers or non-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 non-operating partner could result in significant financial losses.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, commodity pricing levels, and other factors are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future and increase the cost of future debt; past ratings downgrades have required, and any future downgrades may require, us to post letters of credit or other forms of collateral for certain obligations. Throughout 2018, our credit rating remained unchanged by Moody's at Baa3/Stable and Standard and Poor's at BBB/Stable. Any future downgrades could result in additional postings of collateral ranging from approximately $700 million to $1.1 billion, depending upon timing and availability of tax relief.

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

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

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

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

Any indentures and other financing agreements that we enter into in the future may limit our ability to pay cash dividends on our capital stock, including common stock. In addition, under Delaware law, dividends on capital stock may only be paid from "surplus," which is the amount by which the fair value of our total assets exceeds the sum of our total liabilities, including contingent liabilities, and the amount of our capital; if there is no surplus, cash dividends on capital stock may only be paid from our net profits for the then-current and/or the preceding fiscal year. Further, even if we are permitted under our contractual obligations and Delaware law to pay cash dividends on common stock, we may not have sufficient cash to pay dividends in cash on our common stock.

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.
The production rate from oil and gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through exploration and development activities, identify additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves through engineering studies, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase.
We may not realize an adequate return on wells that we drill.
Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The wells we drill or participate in may not be productive, and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors including, but not limited to:

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

Future drilling activities may not be successful, and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.
Material differences between the estimated and actual timing of critical events or costs may affect the completion and commencement of production from development projects.
We are involved in several large development projects, and the completion of these projects may be delayed beyond our anticipated completion dates. Our projects may be delayed by project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, and other unforeseen events. Delays and differences between estimated and actual timing of critical events may adversely affect our large development projects and our ability to participate in large-scale development projects in the future. In addition, our estimates of future development costs are based on current expectation of prices and other costs of equipment and personnel we will need to implement such projects. Our actual future development costs may be significantly higher than we currently estimate. If costs become too high, our development projects may become uneconomic to us, and we may be forced to abandon such development projects.

We may fail to fully identify potential problems related to acquired reserves or to properly estimate those reserves.
Although we perform a review of properties that we acquire that we believe is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in-depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us as a buyer to become sufficiently familiar with the properties to assess fully and accurately their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future production rates and costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates. In addition, there can be no assurance that acquisitions will not have an adverse effect upon our operating results, particularly during the periods in which the operations of acquired businesses are being integrated into our ongoing operations.
Our liabilities could be adversely affected in the event one or more of our transaction counterparties become the subject of a bankruptcy case.
From time to time we have divested noncore or nonstrategic domestic and international assets. The agreements relating to these transactions contain provisions pursuant to which liabilities related to past and future operations have been allocated between the parties by means of liability assumptions, indemnities, escrows, trusts, and similar arrangements. One of the most significant of these liabilities involves the decommissioning of wells and facilities previously owned by us. One or more of the counterparties in these transactions could fail to perform its obligations under these agreements as a result of financial distress. In the event that any such counterparty were to become the subject of a case or proceeding under Title 11 of the United States Code or any other relevant insolvency law or similar law (which we collectively refer to as Insolvency Laws), the counterparty may not perform its obligations under the agreements related to these transactions. In that case, our remedy in the proceeding would be a claim for damages for the breach of the contractual arrangements, which may be either a secured claim or an unsecured claim depending on whether or not we have collateral from the counterparty for the performance of the obligations. Resolution of our claim for damages in such a proceeding may be delayed, and we may be forced to use available cash to cover the costs of the obligations assumed by the counterparties under such agreements should they arise.
Despite the provisions in our agreements requiring purchasers of our state or federal leasehold interests to assume certain liabilities and obligations related to such interests, if a purchaser of such interests becomes the subject of a case or proceeding under relevant Insolvency Laws or becomes unable financially to perform such liabilities or obligations, we would expect the relevant governmental authorities to require us to perform and hold us responsible for such liabilities and obligations. In such event, we may be forced to use available cash to cover the costs of such liabilities and obligations should they arise.
If a court or a governmental authority were to make any of the foregoing determinations or take any of the foregoing actions, or any similar determination or action, it could adversely impact our cash flows, operations, or financial condition.
Crude oil, natural gas, and NGL reserves are estimates, and actual recoveries may vary significantly.
There are numerous uncertainties inherent in estimating crude oil, natural gas, and NGL reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas, and NGLs 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, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the 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 effects of regulations by governmental agencies, including changes to severance and excise taxes;

- future operating costs and capital expenditures; and
- workover and remediation costs.

For these reasons, estimates of the economically recoverable quantities of crude oil, natural gas, and NGLs 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.

Additionally, because some of our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A sizeable portion of our acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

We may incur significant costs related to environmental matters.

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, local, and foreign country 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 cleanup 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. Our efforts to limit our exposure to such liability and cost may prove inadequate and result in significant adverse effects to 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 United States operations are subject to governmental risks.

Our United States 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 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 a Notice to Lessees (NTL No. 2016-N01) significantly revising the obligations of companies operating in the Gulf of Mexico to provide supplemental assurances of performance with respect to plugging, abandonment, and decommissioning obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. While requirements under the NTL have not yet been fully implemented by BOEM, the NTL will likely require that Apache provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to Apache's current ownership interests in various Gulf of Mexico leases. We are working closely with BOEM to make arrangements for the provision of such additional required security, if such security becomes necessary under the NTL. Additionally, we are not able to predict the effect that these changes might have on counterparties to which Apache has sold Gulf of Mexico assets or with whom Apache has joint ownership. Such changes could cause the bonding obligations of such parties to increase substantially, thereby causing a significant impact on the counterparties' solvency and ability to continue as a going concern.

New political developments, the enactment of new or stricter laws or regulations or other governmental actions impacting our United States 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.

Certain countries where we operate, including the United Kingdom, either tax or assess some form of greenhouse gas (GHG) related fees on our operations. Exposure has not been material to date, although a change in existing regulations could adversely affect our cash flows and results of operations. Additionally, there has been discussion in other countries where we operate, including the United States, regarding legislation or regulation of GHG. Any such legislation or regulation, if enacted, could either tax or assess some form of GHG-related fees on our operations and could lead to increased operating expenses or cause us 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 our assets or operations. However, any increase in severe weather could have a material adverse effect on our assets and operations.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, and explosions of natural gas transmission lines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines, and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens, and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance, and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

The present U.S. federal and state income tax laws affecting oil and gas exploration, development, and extraction may be modified by administrative, legislative, or judicial interpretation at any time. Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development.

On December 22, 2017, the Tax Cuts and Jobs Act (the Act) was signed into law. In addition to reducing the U.S. corporate income tax rate from 35 percent to 21 percent effective January 1, 2018, certain provisions in the Act move the U.S. away from a worldwide tax system and closer to a territorial system for earnings of foreign corporations, establishing a participation exemption system for taxation of foreign income. The new law includes a transition rule to effect this participation exemption regime. The Act also includes provisions which could impact or limit the Company’s ability to deduct interest expense or utilize net operating losses beginning in 2018.

The U.S. federal and state income tax laws affecting oil and gas exploration, development, and extraction may be further modified by administrative, legislative, or judicial interpretation at any time. Previous legislative proposals, if enacted into law, could make significant changes to such laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. The passage or adoption of these changes, or similar changes, could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development. We are unable to predict whether any of these changes or other proposals will be enacted. Any such changes could adversely affect our business, financial condition, and results of operations.

Proposed federal, state, or local 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 or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states and political subdivisions are considering legislation, ballot initiatives, executive orders, or other actions to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to potential environmental and physical impacts, including possible contamination of groundwater and drinking water and possible links to induced seismicity. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing or are considering doing so. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in formations with low permeability.

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

International operations have uncertain political, economic, and other risks.

Our operations outside the United States are based primarily in Egypt and the United Kingdom. On a barrel equivalent basis, approximately 44 percent of our 2018 production was outside the United States, and approximately 28 percent of our estimated proved oil and gas reserves on December 31, 2018, were located outside the United States. As a result, a significant portion of our production and resources are subject to the increased political and economic risks and other factors associated with international operations including, but not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation and resource nationalization, and forced renegotiation or modification of existing contracts;
- import and export regulations;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- price control;
- transportation regulations and tariffs;
- constrained oil or natural gas markets dependent on demand in a single or limited geographical area;
- exchange controls, currency fluctuations, devaluations, or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the United States affecting foreign trade, including trade sanctions;
- the effects of the U.K.'s potential withdrawal from the European Union, including any resulting instability in global financial markets or the value of foreign currencies such as the British pound;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;
- the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the United States; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

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

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

A deterioration of conditions in Egypt or changes in the economic and political environment in Egypt could have an adverse impact on our business.

Deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, expropriation of our assets or resource nationalization, and/or forced renegotiation or modification of our existing contracts with EGPC, or threats or acts of terrorism could materially and adversely affect our business, financial condition, and results of operations. Our operations in Egypt, excluding a one-third noncontrolling interest, contributed 24 percent of our 2018 production and accounted for 12 percent of our year-end estimated proved reserves and 20 percent of our estimated discounted future net cash flows.

Our operations are sensitive to currency rate fluctuations.

Our operations are sensitive to fluctuations in foreign currency exchange rates, particularly between the U.S. dollar and the British pound. Our financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect our results of operations, particularly through the weakening of the U.S. dollar relative to other currencies.

We do not always control decisions made under joint operating agreements, and the parties under such agreements may fail to meet their obligations.

We conduct many of our E&P operations through joint operating agreements with other parties under which we may not control decisions, either because we do not have a controlling interest or are not an operator under the agreement. There is risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with ours, and, therefore, decisions may be made which are not what we believe to be in our best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations, and we may be required to fulfill those obligations alone. In either case, the value of our investment may be adversely affected.

We face strong industry competition that may have a significant negative impact on our results of operations.

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

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

Exploration for and production of crude oil, natural gas, and NGLs can be hazardous, involving natural disasters and other events such as blowouts, cratering, fires, explosions, 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. Our international operations are also subject to political risk. The insurance coverage that we maintain against certain losses or liabilities arising from our operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to us against all operational risks.

Certain anti-takeover provisions in our charter and Delaware law could delay or prevent a hostile takeover.

Our charter authorizes our board of directors to issue preferred stock in one or more series and to determine the voting rights and dividend rights, dividend rates, liquidation preferences, conversion rights, redemption rights, including sinking fund provisions and redemption prices, and other terms and rights of each series of preferred stock. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15 percent or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our shareholders.

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We own an approximate 79 percent interest in Altus, which holds substantially all of our former gathering, processing and transmission assets in Alpine High. Altus may be subject to different risks than those described in this Form 10-K.

We own an approximate 79 percent interest in Altus, which holds substantially all of our former gathering, processing and transmission assets in Alpine High. Altus owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas, anchored by midstream service contracts to service Apache's production from its Alpine High resource play. Altus primarily generates revenue by providing fee-based natural gas gathering, compression, processing and transportation services. Given the nature of its business, Altus may be subject to different and additional risks than those described in this Form 10-K. For a description of these risks, please refer to the Form 10-K filed by ALTM.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2018, we did not have any unresolved comments from the SEC staff that were received 180 or more days prior to year-end.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under "Legal Matters" and "Environmental Matters" in Note 9—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

None.

APACHE CORPORATION

PART II

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

During 2018, Apache common stock, par value $0.625 per share, was traded on the New York and Chicago Stock Exchanges and the NASDAQ Global Select Market under the symbol "APA." The closing price of our common stock, as reported on the New York Stock Exchange Composite Transactions Reporting System for January 31, 2019 (last trading day of the month), was $32.82 per share. As of January 31, 2019, there were 375,405,587 shares of our common stock outstanding held by approximately 3,800 stockholders of record and 258,000 beneficial owners.

We have paid cash dividends on our common stock for 54 consecutive years through December 31, 2018. When, and if, declared by our Board of Directors, future dividend payments will depend upon our level of earnings, financial requirements, and other relevant factors.

Information concerning securities authorized for issuance under equity compensation plans is set forth under the caption "Equity Compensation Plan Information" in the proxy statement relating to the Company's 2019 annual meeting of stockholders, which is incorporated herein by reference.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to shares of common stock repurchased by Apache during 2018.

Period	Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs (1)
January 1 to January 31, 2018	—	$—	—	7,827,352
February 1 to February 28, 2018	—	—	—	7,827,352
March 1 to March 31, 2018	—	—	—	7,827,352
April 1 to April 30, 2018	—	—	—	7,827,352
May 1 to May 31, 2018	—	—	—	7,827,352
June 1 to June 30, 2018	—	—	—	7,827,352
July 1 to July 31, 2018	—	—	—	7,827,352
August 1 to August 31, 2018	—	—	—	7,827,352
September 1 to September 30, 2018	924,131	46.38	924,131	6,903,221
October 1 to October 31, 2018	2,030,000	44.59	2,030,000	44,873,221
November 1 to November 30, 2018	3,343,800	36.43	3,343,800	41,529,421
December 1 to December 31, 2018	1,529,402	32.70	1,529,402	40,000,019
Total	7,827,333	$ 38.99		

(1) On May 9, 2013, the Company announced that its Board of Directors authorized the repurchase of up to 30 million shares of the Company's common stock. Additionally, on May 15, 2014, the Company announced that the Board of Directors authorized the repurchase of an additional 10 million shares, supplementing the May 2013 authorization. The Company may buy shares from time to time on the open market, in privately negotiated transactions, or a combination of both. The timing and amounts of any repurchases will be at the discretion of Apache's management and will depend on a variety of factors, including the stock price, corporate and regulatory requirements, and other market and economic conditions. Repurchased shares will be available for general corporate purposes. On October 30, 2018, the Company's Board of Directors authorized the purchase of up to 40 million additional shares of the

Company’s common stock.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company's common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 31, 2013, through December 31, 2018. The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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

* $100 invested on 12/31/13 in stock including reinvestment of dividends.
Fiscal year ending December 31.

	2013	2014	2015	2016	2017	2018
Apache Corporation	$100.00	$73.75	$53.29	$77.62	$52.68	$33.51
S & P's Composite 500 Stock Index	100.00	113.69	115.26	129.05	157.22	150.33
DJ US Expl & Prod Index	100.00	89.23	68.05	84.71	85.81	70.57

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected financial data of the Company and its consolidated subsidiaries over the five-year period ended December 31, 2018. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth in Part IV, Item 15 of this Form 10-K. Certain amounts for prior years have been reclassified to conform to the current presentation. Factors that materially affect the comparability of this information are disclosed in Management's Discussion and Analysis under Item 7 of this Form 10-K.

	As of or for the Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Income Statement Data					
Oil and gas production revenues	$7,348	$5,887	$5,367	$6,510	$12,795
Net income (loss) from continuing operations attributable to common shareholders	40	1,304	(1,372)	(10,844)	(6,653)
Net income (loss) from continuing operations per share:					
Basic	0.11	3.42	(3.62)	(28.70)	(17.32)
Diluted	0.11	3.41	(3.62)	(28.70)	(17.32)
Cash dividends declared per common share	1.00	1.00	1.00	1.00	1.00
Balance Sheet Data					
Total assets	$21,582	$21,922	$22,519	$25,500	$44,264
Long-term debt	8,054	7,934	8,544	8,716	11,178
Total equity	8,812	8,791	7,679	9,490	20,541
Common shares outstanding	375	381	379	378	377

For a discussion of significant acquisitions and divestitures, see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

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

Apache Corporation, a Delaware corporation formed in 1954, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids (NGL). Apache currently has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). Apache also has exploration interests in Suriname that may, over time, result in a reportable discovery and development opportunity.

The following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K, and the risk factors and related information set forth in Part I, Item 1A and Part II, Item 7A of this Form 10-K.

Overview of 2018 Results

Apache's mission is to grow in an innovative, safe, environmentally responsible, and profitable manner for the long-term benefit of our stakeholders. Apache is focused on rigorous portfolio management, disciplined financial structure, and optimization of returns. The Company primarily focused its 2018 capital program on developing Alpine High, building associated Alpine High infrastructure, and increasing production and performance in its other Permian Basin plays.

Apache's U.S. assets are complemented by its international assets in Egypt and the North Sea, each of which adds to the Company's deep inventory of exploration and development opportunities and generates cash flows in excess of current capital investments, facilitating the Company's ability to develop Alpine High while maintaining financial flexibility.

In November 2018 the Company completed a transaction with Kayne Anderson Acquisition Corp. to create a publicly traded, pure-play, Permian Basin to Gulf Coast midstream C-corporation anchored by Apache's gathering, processing, and transmission assets at Alpine High with ownership or options for participation in five joint venture pipelines. This strategic transaction facilitates funding the capital intensive midstream infrastructure and enhances the allocation of Apache's capital to further development of the vast Alpine High upstream resource base, while maintaining control and a significant stake in the contributed assets. For further information regarding this transaction, please see "Operational Highlights" below, and also refer to Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

During 2018, Apache reported net income attributable to common stock of $40 million, or $0.11 per diluted common share, compared to $1.3 billion, or $3.41 per share in 2017. The 2018 results include asset impairments of $511 million as the Company continues to redirect capital from non-core assets and a $94 million charge for early extinguishment of debt. These charges directly impact comparability to the prior year and partially offset realized benefits from higher average crude oil and NGL prices and production. Additionally, 2017 results were materially benefited from a $627 million gain on asset sales.

Daily production in 2018 averaged 466 Mboe/d, an increase of 2 percent from 2017. Excluding asset divestitures, Apache's worldwide equivalent daily production increased 9 percent, driven primarily by activity in the Permian Basin. Realized oil prices in 2018 were considerably higher than the previous year, particularly Dated Brent, which has provided increased operating cash flow to reinvest in the Company's core development areas.

Apache generated $3.8 billion in cash from operating activities in 2018, up $1.3 billion from the prior year, $628 million of cash proceeds from the sale of a noncontrolling interest in its Alpine High midstream assets, and an additional $138 million of cash proceeds from non-core asset and leasehold divestments. Apache ended the year with $714 million of cash and cash equivalents, a decrease of $954 million from year-end 2017. Apache continuously monitors changes in its operating environment and has the ability, with its dynamic capital allocation process, to adjust the Company's capital investment program to levels commensurate with cash from operating activities and to maximize value for Apache's shareholders over the long term. During the year, the Company took several steps to improve its debt portfolio, issuing $1.0 billion in aggregate principal amount of senior unsecured notes and concurrently repurchasing $731 million in aggregate principal amount of certain outstanding notes. These transactions extended debt maturities, reduced the Company's cost of debt, modernized its standard indenture terms, and, in conjunction with the repayment of $550 million of debt that matured during 2018, reduced debt by $281 million from 2017 year-end levels. In late 2018, the Company re-initiated share repurchase activity under its existing authorization and repurchased over 7.8 million shares. Since the inception of the program in 2013, the Company has purchased approximately 40 million shares through the end of 2018. The Company also obtained authorization from the Company's Board of Directors to purchase an additional 40 million shares of the Company's common stock.

Operational Highlights

Key operational highlights for the year include:

United States

- U.S. onshore production averaged 256 Mboe/d, up 28 percent relative to 2017, reflecting the success of the Midland Basin drilling program and the continued production ramp-up at Alpine High.
- The Permian region averaged 17 operated rigs during the year, drilling 284 gross wells. Approximately 43 percent of the region's production is crude oil and 21 percent is NGLs. Combined, this represents 44 percent of Apache's worldwide liquids production for 2018. The region averaged 211 Mboe/d and contributed $2.7 billion of revenues during 2018. Fourth-quarter 2018 production increased 33 percent from the comparative 2017 quarter, a reflection of the success of the Midland Basin drilling program and the continued production ramp-up at Alpine High.
- In the fourth quarter of 2018, the Company completed the previously announced agreement with Kayne Anderson Acquisition Corp. (KAAC) and its then wholly-owned subsidiary Altus Midstream LP (collectively, Altus). Subsequent to the transaction, KAAC was renamed to Altus Midstream Company (ALTM).

Upon closing of the transaction, KAAC contributed approximately $628 million of cash, net of transaction expenses, into Altus Midstream LP. The cash will primarily be used to fund future development of the Alpine High midstream assets.

In exchange for the contribution of its Alpine High midstream assets, Apache received an approximate 79 percent ownership interest in Altus.

Altus owns gas gathering, processing, and transmission assets in the Permian Basin of West Texas, anchored by midstream contracts to service Apache's production from its Alpine High resource play. Altus primarily generates revenue by providing fee-based natural gas gathering, compression, processing, and transportation services. Additionally, Altus Midstream LP and/or its subsidiaries have equity ownership in third-party pipeline projects and hold options to purchase equity ownerships in other pipeline projects in the region.

International

- The Egypt region averaged 12 rigs and drilled or participated in drilling 115 gross wells. During 2018, Egypt's gross production and net equivalent production averaged 336 Mboe/d and 149 Mboe/d, respectively. Egypt's gross production increased 1 percent from 2017, while net equivalent production decreased 8 percent from 2017, primarily the result of the impact of higher Brent oil prices on cost recovery volumes as a function of the Company's production sharing contracts. The region contributed $2.7 billion of revenues during the year.
- The North Sea region averaged 3 rigs during 2018, drilling 10 gross wells. During the year, the region averaged production of 56 Mboe/d and contributed $1.3 billion of revenues. Production declined 3 percent from 2017, primarily the result of natural decline offset by a development well coming online at the Callater field and initial production at Garten during the fourth quarter of 2018.

For a more detailed discussion related to Apache's various geographic regions, please refer to the "Geographic Area Overviews" section set forth in Part I, Item 1 and 2 of this Form 10-K.

Acquisition and Divestiture Activity

Over Apache's 60-year history, the Company has repeatedly demonstrated its ability to capitalize quickly and decisively on changes in its industry and economic conditions. A key component of this strategy is to continuously review and optimize Apache's portfolio of assets in response to these changes. Most recently, Apache has completed a series of divestitures designed to monetize nonstrategic assets and enhance Apache's portfolio in order to allocate resources to more impactful exploration and development opportunities. These divestments comprised primarily capital intensive projects and assets that were not accretive to earnings in the near-term, and included all of Apache's operations in Canada and Australia. These divestments include:

- U.S. and North Sea Divestitures During 2018, in addition to the Altus transaction discussed above, Apache completed the sale of certain non-core assets, primarily leasehold acreage in the U.S. and North Sea regions, in multiple transactions for total cash proceeds of approximately $138 million.
- Canadian Operations On June 30, 2017, Apache completed the sale of its Canadian assets at Midale and House Mountain for total cash proceeds of approximately $228 million. In August of 2017, Apache completed the sale of its remaining Canadian operations for cash proceeds of approximately $478 million.

- U.S. Leasehold Divestitures During 2017, Apache completed the sale of certain non-core assets, primarily leasehold acreage in the Permian and Midcontinent/Gulf Coast regions, in multiple transactions for total cash proceeds of $798 million.
- North Sea Gathering Transportation and Processing (GTP) Facility In November 2017, Apache completed the sale of its 30.28 percent interest in the SAGE gas plant and its 60.56 percent interest in the Beryl pipeline in the North Sea to Ancala Midstream Acquisitions Limited. A refundable deposit of $134 million was received in the fourth quarter of 2016 in connection with this transaction, and was recorded in "Other current liabilities" on the consolidated balance sheet as of December 31, 2016. In November 2017, Apache completed the sale and the liability related to the refundable deposit was released. No additional proceeds were received.

For detailed information regarding Apache's acquisitions and divestitures, please refer to Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Results of Operations
Oil and Gas Revenues
Apache's oil and gas revenues by region are as follows:

	For the Year Ended December 31,								
	2018			2017			2016		
	$ Value	% Contribution		$ Value	% Contribution		$ Value	% Contribution	
	($ in millions)								
Total Oil Revenues:									
United States	$2,271	39	%	$1,616	35	%	$1,499	36	%
Canada	—	—		110	3	%	180	4	%
North America	2,271	39	%	1,726	38	%	1,679	40	%
Egypt (1)	2,396	41	%	1,901	41	%	1,657	40	%
North Sea	1,179	20	%	971	21	%	836	20	%
International (1)	3,575	61	%	2,872	62	%	2,493	60	%
Total(1)	$5,846	100	%	$4,598	100	%	$4,172	100	%
Total Natural Gas Revenues:									
United States	$458	50	%	$368	38	%	$314	33	%
Canada	—	—		104	11	%	146	15	%
North America	458	50	%	472	49	%	460	48	%
Egypt (1)	339	37	%	395	41	%	389	40	%
North Sea	122	13	%	92	10	%	118	12	%
International (1)	461	50	%	487	51	%	507	52	%
Total(1)	$919	100	%	$959	100	%	$967	100	%
Total NGL Revenues:									
United States	$550	94	%	$287	87	%	$184	81	%
Canada	—	—		17	5	%	17	7	%
North America	550	94	%	304	92	%	201	88	%
Egypt (1)	13	2	%	11	3	%	11	5	%
North Sea	20	4	%	15	5	%	16	7	%
International (1)	33	6	%	26	8	%	27	12	%
Total (1)	$583	100	%	$330	100	%	$228	100	%
Total Oil and Gas Revenues:									
United States	$3,279	45	%	$2,271	39	%	$1,997	37	%
Canada	—	—		231	4	%	343	7	%
North America	3,279	45	%	2,502	43	%	2,340	44	%
Egypt (1)	2,748	37	%	2,307	39	%	2,057	38	%
North Sea	1,321	18	%	1,078	18	%	970	18	%
International (1)	4,069	55	%	3,385	57	%	3,027	56	%
Total (1)	$7,348	100	%	$5,887	100	%	$5,367	100	%

(1) Amounts include revenue attributable to a noncontrolling interest in Egypt.

Production

The following table presents production volumes by region:

	For the Year Ended December 31,				
	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Oil Volume – b/d:					
United States	104,800	15%	91,489	(12)%	103,827
Canada	—	NM	6,643	(49)%	13,081
North America	104,800	7%	98,132	(16)%	116,908
Egypt[(1)(2)]	93,656	(4)%	97,242	(6)%	103,719
North Sea	46,953	(4)%	48,889	(11)%	54,630
International	140,609	(4)%	146,131	(8)%	158,349
Total	245,409	—	244,263	(11)%	275,257
Natural Gas Volume – Mcf/d:					
United States	593,254	50%	394,366	—	396,227
Canada	—	NM	131,479	(46)%	242,602
North America	593,254	13%	525,845	(18)%	638,829
Egypt[(1)(2)]	326,811	(15)%	386,194	(1)%	391,968
North Sea	45,466	—	45,521	(37)%	71,751
International	372,277	(14)%	431,715	(7)%	463,719
Total	965,531	1%	957,560	(13)%	1,102,548
NGL Volume – b/d:					
United States	57,451	18%	48,674	(10)%	54,165
Canada	—	NM	2,827	(51)%	5,731
North America	57,451	12%	51,501	(14)%	59,896
Egypt[(1)(2)]	923	13%	816	(25)%	1,084
North Sea	1,189	3%	1,149	(33)%	1,703
International	2,112	7%	1,965	(29)%	2,787
Total	59,563	11%	53,466	(15)%	62,683
BOE per day:[(3)]					
United States	261,126	27%	205,891	(8)%	224,029
Canada	—	NM	31,383	(47)%	59,246
North America	261,126	10%	237,274	(16)%	283,275
Egypt[(1)(2)]	149,048	(8)%	162,424	(5)%	170,131
North Sea[(4)]	55,719	(3)%	57,624	(16)%	68,292
International	204,767	(7)%	220,048	(8)%	238,423
Total	465,893	2%	457,322	(12)%	521,698

(1) Gross oil, natural gas, and NGL production in Egypt were as follows:

	2018	2017	2016
Oil (b/d)	206,378	198,335	209,659
Natural Gas (Mcf/d)	769,468	805,478	827,202
NGL (b/d)	1,502	1,353	1,861

(2) Includes net production volumes per day attributable to a noncontrolling interest in Egypt of:

Oil (b/d)	31,240	32,461	34,530
Natural Gas (Mcf/d)	109,169	128,756	130,856
NGL (b/d)	308	272	361

(3)

The table shows production on a barrel of oil equivalent basis (boe) in which natural gas is converted to an equivalent barrel of oil based on a ratio of 6 Mcf to 1 bbl. This ratio is not reflective of the price ratio between the two products.

(4) Average sales volumes from the North Sea were 55,568 boe/d, 58,177 boe/d, and 66,872 boe/d for 2018, 2017, and 2016, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

NM — Not meaningful

Pricing

The following table presents pricing information by region:

	For the Year Ended December 31,				
	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Average Oil Price - Per barrel:					
United States	$59.36	23%	$48.40	23%	$39.43
Canada	—	NM	45.25	20%	37.62
North America	59.36	23%	48.18	23%	39.23
Egypt	70.09	31%	53.57	23%	43.66
North Sea	69.02	28%	53.81	25%	42.93
International	69.73	30%	53.65	24%	43.41
Total	65.30	27%	51.46	24%	41.63
Average Natural Gas Price - Per Mcf:					
United States	$2.12	(17)%	$2.56	18%	$2.17
Canada	—	NM	2.17	32%	1.64
North America	2.12	(14)%	2.46	25%	1.97
Egypt	2.84	1%	2.80	3%	2.71
North Sea	7.33	32%	5.54	23%	4.51
International	3.39	10%	3.09	3%	2.99
Total	2.61	(5)%	2.74	14%	2.40
Average NGL Price - Per barrel:					
United States	$26.28	63%	$16.14	74%	$9.28
Canada	—	NM	16.39	101%	8.15
North America	26.28	63%	16.15	76%	9.17
Egypt	39.17	6%	36.79	28%	28.68
North Sea	45.84	27%	36.22	50%	24.20
International	42.93	18%	36.46	41%	25.94
Total	26.87	59%	16.90	70%	9.92

NM — Not meaningful

Crude Oil Prices

A substantial portion of our crude oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of the Company's control. Average realized crude oil prices for 2018 were up 27 percent compared to 2017, a direct result of the rising benchmark oil prices over the past year. Crude oil prices realized in 2018 averaged $65.30 per barrel.

Continued volatility in the commodity price environment reinforces the importance of our asset portfolio. While the market price received for natural gas varies among geographic areas, crude oil tends to trade within a global market. Price movements for all types and grades of crude oil generally move in the same direction.

Natural Gas Prices

Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions. Our primary markets include North America, Egypt, and the U.K. An overview of the market conditions in our primary gas-producing regions follows:

- North America has a common market; most of our gas is sold on a monthly or daily basis at either monthly or daily market prices. Our U.S. regions averaged $2.12 per Mcf in 2018, down from $2.56 per Mcf in 2017.

- In Egypt, our gas is sold to Egyptian General Petroleum Corporation (EGPC), primarily under an industry pricing formula indexed to Dated Brent crude oil with a minimum gas price of $1.50 per MMBtu and a maximum gas price of $2.65 per MMBtu, plus an upward adjustment for liquids content. Overall, the region averaged $2.84 per Mcf in 2018, up 1 percent from the prior year.

Natural gas from the North Sea Beryl field is processed through the SAGE gas plant. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The region averaged $7.33 per Mcf in 2018, a 32 percent increase from an average of $5.54 per Mcf in 2017.

NGL Prices

Apache's NGL production is sold under contracts with prices at market indices based on local supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Crude Oil Revenues

2018 vs. 2017 Crude oil revenues for 2018 totaled $5.8 billion, a $1.2 billion increase from the 2017 total of $4.6 billion, primarily a result of 27 percent higher average realized prices. Average daily production in 2018 was 245.4 Mb/d, with prices averaging $65.30 per barrel. Crude oil accounted for 80 percent of Apache's 2018 oil and gas production revenues and 53 percent of its worldwide production.

Worldwide crude oil production increased 1.1 Mb/d compared to 2017, primarily the result of the drilling program in the Permian region offset by the Canada divestitures and natural decline.

2017 vs. 2016 Crude oil revenues for 2017 totaled $4.6 billion, a $426 million increase from the 2016 total of $4.2 billion. An 11 percent decrease in average daily production reduced 2017 revenues by $559 million compared to 2016, while 24 percent higher average realized prices increased revenues by $985 million. Average daily production in 2017 was 244.3 Mb/d, with prices averaging $51.46 per barrel. Crude oil accounted for 78 percent of Apache's 2017 oil and gas production revenues and 53 percent of its worldwide production.

Worldwide crude oil production decreased 31.0 Mb/d compared to 2016, primarily the result of the Canada divestitures and natural decline.

Natural Gas Revenues

2018 vs. 2017 Natural gas revenues for 2018 totaled $919 million, a $40 million decrease from the 2017 total of $959 million. A 1 percent increase in average production increased 2018 revenues by $7 million compared to 2017, while 5 percent lower average realized prices decreased revenues by $47 million. Average daily production in 2018 was 966 MMcf/d, with prices averaging $2.61 per Mcf. Natural gas accounted for 12 percent of Apache's 2018 oil and gas production revenues and 34 percent of its worldwide production.

Worldwide gas production increased 8.0 MMcf/d compared to 2017, primarily the result of the Alpine High development partially offset by the Canada divestitures and natural decline.

2017 vs. 2016 Natural gas revenues for 2017 totaled $959 million, an $8 million decrease from the 2016 total of $967 million. A 13 percent decrease in average production reduced 2017 revenues by $148 million compared to 2016, while 14 percent higher average realized prices increased revenues by $140 million. Average daily production in 2017 was 958 MMcf/d, with prices averaging $2.74 per Mcf. Natural gas accounted for 16 percent of Apache's 2017 oil and gas production revenues and 35 percent of its worldwide production.

Worldwide gas production decreased 145.0 MMcf/d compared to 2016, primarily the result of the Canada divestitures, maintenance activities in the North Sea, and natural decline.

NGL Revenues

2018 vs. 2017 NGL revenues for 2018 totaled $583 million, a $253 million increase from 2017. An 11 percent increase in average production increased 2018 revenues by $59 million compared to 2017, while 59 percent higher average realized prices increased revenues by $194 million. Average daily production in 2018 was 59.6 Mb/d, with prices averaging $26.87 per barrel. NGLs accounted for nearly 8 percent of Apache's 2018 oil and gas production revenues and 13 percent of its worldwide production.

2017 vs. 2016 NGL revenues for 2017 totaled $330 million, a $102 million increase from 2016. A 15 percent decrease in average production reduced 2017 revenues by $58 million compared to 2016, while 70 percent higher average realized prices increased revenues by $160 million. Average daily production in 2017 was 53.5 Mb/d, with prices averaging $16.90 per barrel. NGLs accounted for nearly 6 percent of Apache's 2017 oil and gas production revenues and 12 percent of its worldwide production.

Altus Revenues

Apache is the largest single owner of the voting common stock of ALTM, and has an approximate 79 percent interest in Altus. Altus generates revenue primarily by providing fee-based natural gas gathering, compression, processing, and transportation services. Altus owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas, anchored by midstream service contracts to service Apache's production from its Alpine High resource play, which commenced production in May 2017. The amount and pace of upstream development activity by Apache of its Alpine High play will impact Altus's aggregate gathering and processing volumes over time. Additionally, other producers are also developing oil and gas plays in surrounding areas that are expected to provide attractive opportunities to enter into third-party processing and gathering agreements.

During 2018 and 2017, midstream services revenues totaling $77 million and $15 million, respectively, were generated through fee-based contractual arrangements with Apache and eliminated upon consolidation. Altus did not generate any services revenues in 2016.

Operating Expenses

The table below presents a comparison of the Company's expenses on an absolute dollar basis. The Company's discussion may reference expenses on a boe basis, on an absolute dollar basis or both, depending on context. All operating expenses include costs attributable to a noncontrolling interest in Egypt and ALTM. Operating expenses for all periods exclude discontinued operations in Australia.

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Lease operating expenses	$1,439	$1,384	$1,494
Gathering, transmission, and processing	348	195	200
Taxes other than income	215	151	126
Exploration	503	549	473
General and administrative	431	395	410
Transaction, reorganization, and separation	28	16	39
Depreciation, depletion and amortization:			
Oil and gas property and equipment	2,265	2,136	2,460
GTP assets	83	73	69
Other assets	57	71	89
Asset retirement obligation accretion	108	130	156
Impairments	511	8	1,103
Financing costs, net	478	397	417

Lease Operating Expenses (LOE)

LOE includes several key components, such as direct operating costs, repair and maintenance, and workover costs. Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as rig rates, labor, boats, helicopters, materials, and supplies. Oil, which contributed more than half of Apache's 2018 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

During 2018, LOE increased $55 million, or 4 percent, on an absolute dollar basis compared to 2017. On a per-unit basis, LOE increased $0.19, or 2 percent compared to 2017, from $8.28 per boe to $8.47 per boe. The increase in both absolute dollar basis and per-unit basis is primarily a result of rising costs commensurate with higher commodity prices realized during 2018. During 2017, LOE decreased $110 million, or 7 percent, on an absolute dollar basis compared to 2016. On a per-unit basis, LOE increased $0.43, or 5 percent, compared to 2016. The per-barrel increase during 2017 is primarily the result of declines in production combined with generally rising costs commensurate with higher commodity prices realized during 2017.

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Gathering, Transmission, and Processing

Gathering, transmission, and processing (GTP) expenses include upstream transmission costs paid to a third-party carrier and to Altus, as well as costs associated with gas processing. GTP expenses also include midstream operating costs incurred by Altus. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Third-party transmission and processing costs	$294	$179	$200
Midstream service affiliate costs	77	15	—
Upstream transmission and processing costs	371	194	200
Midstream operating expenses	54	16	—
Intersegment eliminations	(77)	(15)	—
Total GTP costs	$348	$195	$200

2018 vs. 2017 GTP costs increased $153 million from 2017. Upstream transmission and processing costs increased from $1.16 per boe in 2017 to $2.16 per boe in 2018. The increase is primarily the result of the reclassification of certain transportation charges from revenues to GTP expense as a result of the adoption of new revenue recognition accounting rules effective January 1, 2018, as well as the ramp-up of midstream operations at Alpine High, partially offset by Apache’s exit from Canada.

2017 vs. 2016 GTP costs decreased $5 million from 2016. The decrease was directly related to the Canadian divestitures that closed in August 2017.

Taxes Other Than Income

Taxes other than income primarily consist of severance taxes on properties onshore and in state waters off the coast of the U.S. and ad valorem taxes on properties in the U.S. Severance taxes are generally based on a percentage of oil and gas production revenues. We are also subject to a variety of other taxes, including U.S. franchise taxes.

2018 vs. 2017 Taxes other than income totaled $215 million, an increase of $64 million from 2017. The increase is primarily a result of severance taxes being impacted by higher production in the Permian region and higher commodity prices during 2018 compared to 2017.

2017 vs. 2016 Taxes other than income totaled $151 million in 2017, an increase of $25 million from 2016. The increase is primarily a result of higher commodity prices during 2017 compared to 2016.

Exploration Expense

Exploration expense includes unproved leasehold impairments, exploration dry hole expense, geological and geophysical expense, and the costs of maintaining and retaining unproved leasehold properties. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Unproved leasehold impairments	$214	$246	$272
Dry hole expense	137	183	81
Geological and geophysical expense	55	47	44
Exploration overhead and other	97	73	76
Total Exploration expense	$503	$549	$473

2018 vs. 2017 Unproved leasehold impairments decreased $32 million and dry hole expense decreased $46 million compared to 2017, primarily related to higher exploratory well success rates compared to the prior year. Delay rentals and other exploration lease maintenance costs trended higher in 2018 to preserve key acreage holdings, reflecting the increase in “Exploration overhead and other.”

2017 vs. 2016 Unproved leasehold impairments decreased $26 million compared to 2016, primarily a result of stabilized commodity and leasehold prices during 2017. Dry hole expense increased $102 million compared to 2016, primarily related to unsuccessful international offshore exploration.

General and Administrative (G&A) Expenses

2018 vs. 2017 G&A expenses increased $36 million, or 9 percent, from 2017. The increase in G&A expense was primarily related to higher incentive and stock-based compensation in 2018 compared to 2017, slightly offset by the Canadian divestitures during 2017.

2017 vs. 2016 G&A expenses decreased $15 million, or 4 percent, from 2016. The decrease in G&A expense was primarily related to lower incentive compensation in 2017 compared to 2016, and the Canadian divestitures.

Transaction, Reorganization, and Separation Costs

Apache recorded $28 million, $16 million and $39 million of expenses during 2018, 2017, and 2016, respectively, primarily related to company reorganization, including separation costs, investment banking fees and other associated costs. The charges for 2018 include $22 million for consulting and legal fees related to divestitures and the Altus transaction and $6 million related to employee separation and other reorganization efforts.

Depreciation, Depletion and Amortization (DD&A)

2018 vs. 2017 Oil and gas property DD&A expense of $2.3 billion in 2018 increased $129 million compared to 2017. The Company's oil and gas property DD&A rate increased $0.55 per boe in 2018 compared to 2017, from $12.78 to $13.33. The primary factor driving higher absolute dollar expense was an increase in capital spending primarily in the Permian and Alpine High regions as a result of drilling and development activity. The increase on an absolute dollar basis was partially offset by the sale of Apache's Canadian operations. GTP depreciation increased $10 million in 2018 compared to 2017, primarily a result of capital spending on Altus infrastructure. Other asset depreciation decreased $14 million compared to 2017 as a result of the Canadian divestiture.

2017 vs. 2016 Oil and gas property DD&A expense of $2.1 billion in 2017 decreased $324 million compared to 2016. The Company's oil and gas property DD&A rate decreased $0.14 to $12.78 per boe in 2017 compared to 2016. The primary factor driving lower absolute dollar expense was a decrease in production volumes from the comparative prior-year periods. Other asset depreciation decreased $18 million compared to 2016 primarily related to Canadian divestitures.

Impairments

During 2018, the Company recorded asset impairments totaling $511 million in connection with fair value assessments, including $328 million for oil and gas proved properties in the U.S. and Egypt, $56 million impairment of a gathering and processing facility in Oklahoma, $113 million for the impairment of an equity method investment based on a negotiated sales price, a $10 million impairment on the carrying values of the associated capitalized exploratory well costs related to the sale of unproved properties in the North Sea, and $4 million for inventory write-downs.

During 2017, the Company recorded asset impairments in connection with fair value assessments totaling $8 million for a U.K. Petroleum Revenue Tax (PRT) decommissioning asset that is no longer expected to be realizable from future abandonment activities in the North Sea.

During 2016, the Company recorded asset impairments totaling $1.1 billion in connection with fair value assessments, including $486 million for the impairment of the recoverable value of the PRT decommissioning asset, $427 million impairments of oil and gas proved properties in the U.S. and Canada, $135 million impairments of certain GTP facilities in the North Sea, and $55 million for inventory write-downs.

The following table presents a summary of asset impairments recorded for 2018, 2017, and 2016:

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Oil and gas proved property	$328	$ —	$427
GTP facilities	56	—	135
Equity method investment	113	—	—
Capitalized exploratory well costs	10	—	—
PRT decommissioning asset	—	8	486
Inventory	4	—	55
Total impairments	$511	$ 8	$1,103

Financing Costs, Net

Financing costs incurred during the period comprised the following:

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Interest expense	$ 441	$ 457	$ 464
Amortization of debt issuance costs	9	9	8
Capitalized interest	(44)	(51)	(48)
Loss on extinguishment of debt	94	1	1
Interest income	(22)	(19)	(8)
Total Financing costs, net	$ 478	$ 397	$ 417

2018 vs. 2017 Net financing costs increased $81 million from 2017. The increase is primarily related to a $94 million loss on extinguishment of debt, an increase of $3 million in interest income, a decrease of $7 million in capitalized interest, and a decrease of $16 million in interest expense.

2017 vs. 2016 Net financing costs decreased $20 million from 2016. The decrease is primarily related to an increase of $11 million in interest income, an increase of $3 million in capitalized interest, and a decrease of $7 million in interest expense.

Provision for Income Taxes

The 2018 income tax expense totaled $672 million. During 2018, Apache's effective tax rate was impacted primarily by the adjustment to the provisional amounts recorded in 2017 related to the enactment of the Tax Cuts and Jobs Act (the Act) and an increase in the Company's valuation allowance.

On December 22, 2017, the Act was signed into law. In addition to reducing the corporate income tax rate from 35 percent to 21 percent effective January 1, 2018, certain provisions in the Act move the U.S. away from a worldwide tax system and closer to a territorial system for earnings of foreign corporations, establishing a participation exemption system for taxation of foreign income. The new law includes a transition rule to effect this participation exemption regime. As a result of the enacted legislation, taxpayers were required to include in taxable income for the tax year ending December 31, 2017, the pro rata share of deferred income of each specified foreign corporation with respect to which the taxpayer is a U.S. shareholder. In 2017, the Company recorded a $419 million provisional deferred tax expense attributable to the deemed repatriation of foreign earnings required under the Act.

Also on December 22, 2017, the SEC staff issued Staff Accounting Bulletin No. 118 (SAB 118) which provides guidance for the application of Accounting Standards Codification (ASC) Topic 740, Income Taxes, for the income tax effects of the Act. SAB 118 provides a measurement period which should not extend beyond one year of the enactment date of the Act. In 2018, the Company recorded an additional $103 million deferred tax expense attributable to the deemed repatriation of foreign earnings. This deferred tax expense combined with the provisional amount recorded in 2017 were fully offset by available foreign tax credits. The Company completed its analysis of the income tax effects of the Act in the fourth quarter of 2018.

The 2017 income tax benefit totaled $585 million. During 2017, Apache's effective tax rate was impacted primarily by the decrease in deferred taxes associated with its investments in foreign subsidiaries, gains on the sale of oil and gas properties, the increase in the Company's valuation allowance, and a decrease in the U.S. corporate income tax rate causing a remeasurement of the Company's deferred tax asset.

The 2016 income tax benefit from continuing operations totaled $442 million. During 2016, Apache's effective tax rate was impacted primarily by non-cash impairments of the carrying value of the Company's oil and gas properties, non-cash impairments of the Company's PRT decommissioning asset, the impact of the change in U.K. statutory income tax rate, and an increase in the amount of valuation allowances on U.S. and Canadian deferred tax assets.

In 2016, the U.K. government enacted Finance Bill 2016, which provides income tax relief to Exploration and Production (E&P) companies operating in the North Sea through a reduction of the Supplementary Charge from 20 percent to 10 percent, effective January 1, 2016. As a result of the enacted legislation in the third quarter of 2016, the Company recorded a deferred tax benefit of $238 million related to the remeasurement of the Company's December 31, 2015, U.K. deferred income tax liability.

Apache recorded a full valuation allowance against its U.S. net deferred tax assets. Apache will continue to maintain a full valuation allowance on its U.S. net deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of this allowance.

For additional information regarding income taxes, please refer to Note 8—Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Capital and Operational Outlook

Apache currently plans to invest $2.4 billion in its upstream oil and gas activities in 2019, of which 70 to 75 percent will be allocated within the United States. Apache's planned upstream capital investment excludes a one-third noncontrolling interest of capital investment in Egypt for its share of operations. Apache's $2.4 billion upstream investment plan represents an approximately 22 percent reduction compared to 2018 levels, as well as a significant reduction from the Company's previous 2019 investment guidance. The revised capital outlook was in response to the rapid fourth quarter 2018 decline in oil prices and Apache's decision to lower its U.S. rig count. With this and other activity reductions, Apache believes the current upstream capital spending for the first quarter of 2019 will underpin its efforts to achieve the full-year capital target.

Despite the significant decrease in planned capital spending, production growth will continue as the Company benefits from productivity and efficiency gains in its core areas. Apache projects fourth quarter 2018 to fourth quarter 2019 production growth rates of 6 to 10 percent, adjusted for the noncontrolling interest in Egypt and tax volumes. The Company expects 12 to 16 percent growth for its U.S. regions. Approximately five percent growth is expected to be Permian Basin oil, which is driven by a continued focus in Apache's core Wildfire, Powell and Azalea development fields. As the result of reduced rig activity in the Alpine High play, the Company's new 2019 Alpine High production volume outlook is 85 to 90 Mboe per day on average for the year. Apache's drilling focus will shift away from dry gas drilling to a higher percentage of rich gas development, primarily in the Northern flank of the field. With expected cryogenic processing capacity being brought on-line throughout the second half of 2019, the Company believes significant uplift in cash margins should be realized.

Over the same time period, forecasts show a shallow decline rate for the international regions given planned investment levels. Egypt and the North Sea operations, however, are anticipated to continue generating cash flow in excess of capital investments. The North Sea will maintain a similar activity set to the prior year. Egypt activity will focus on advancing a large-scale seismic shoot and prospect identification program. The region will also be drilling exploration and delineation wells in each of its new concession areas, thereby establishing a foundation for potential growth.

Assuming WTI oil prices in the $50 to $55 per barrel range, Apache anticipates an upstream capital program of $2.5 billion to $2.8 billion in 2020 and 2021. Management believes this investment level is capable of generating continued production growth, with the U.S. as the primary driver.

Apache also anticipates additional investments in the continued capital development of the assets of Altus of approximately $325 million in 2019, approximately $185 million in 2020, and approximately $200 million in 2021. The investment will primarily be directed toward the construction of additional gathering, compression, processing, and transmission facilities, including three forecasted cryogenic processing plants expected to be in service during

2019 with combined nameplate capacity of approximately 600 MMcf/d. Additional capacity will be added over the next several years to facilitate production increases from Alpine High and potential third-party volumes. Cash from the Altus transaction and future ALTM and/or Altus Midstream LP financing activities are expected to fund future development of the Altus assets.

Additionally, Altus Midstream LP and/or its subsidiaries obtained the right, but not the obligation, to exercise options to acquire equity interests in five separate joint venture pipelines (Pipeline Options). The option to enter into a 15 percent ownership stake in the Gulf Coast Express Pipeline LLC (GCX) natural gas pipeline was exercised in December 2018 for $91 million. Apache anticipates Altus Midstream LP and/or its subsidiaries to exercise the remaining four Pipeline Options in 2019 and early 2020. Assuming each Pipeline Option is exercised, approximately $1.6 billion of total capital spending by Altus Midstream LP and/or its subsidiaries is estimated for the exercise of these remaining options and the associated capital requirements expected to be incurred until the associated pipelines are in service. This includes approximately $1.3 billion in 2019 and approximately $340 million in 2020. The following table provides additional information regarding the exercise of the Pipeline Options:

	EPIC Option(1)	Salt Creek Option	Shin Oak Option	Permian Highway Option(2)
Expiration Date	February 1, 2019	January 31, 2020	60 days following in-service date	September 4, 2019
Option Percentage	15%	50%	33%	27%
Estimated Exercise Price(3)	$52 million	$51 million	$500 million	$232 million

(1) Subsequent to the balance sheet date, the EPIC Option was exercised on February 1, 2019 and is expected to close in the first quarter of 2019.

(2) Upon exercise of the Permian Highway Pipeline Option, Altus Midstream LP may acquire an additional 1 percent interest in GCX.

(3) Estimated exercise price represents Altus Midstream LP’s proportionate share of capital expenditures made with respect to the applicable project prior to such exercise, plus financing charges associated with such capital expenditures (exercise price). There are no costs associated with exercising the Options other than the exercise price. However, Altus Midstream LP and/or its subsidiaries will be required to fund its pro rata share of capital expenditures after the exercise date.

Capital Resources and Liquidity

Operating cash flows are the Company’s primary source of liquidity. We may also elect to utilize available cash on hand, committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the sale of nonstrategic assets for all other liquidity and capital resource needs.

Apache’s operating cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices, as well as costs and sales volumes. Significant changes in commodity prices impact Apache’s revenues, earnings and cash flows. These changes potentially impact Apache’s liquidity if costs do not trend with changes in commodity prices. Historically, costs have trended with commodity prices, albeit on a lag. Sales volumes also impact cash flows; however, they have a less volatile impact in the short term.

Apache’s long-term operating cash flows are dependent on reserve replacement and the level of costs required for ongoing operations. Cash investments are required to fund activity necessary to offset the inherent declines in production and proved crude oil and natural gas reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of Apache’s drilling program and our ability to add reserves economically. Changes in commodity prices also impact estimated quantities of proved reserves.

Apache believes the liquidity and capital resource alternatives available to the Company, combined with proactive measures to adjust its capital budget to reflect volatile commodity prices and anticipated operating cash flows, will be adequate to fund short-term and long-term operations, including Apache’s capital spending program, repayment of debt maturities, payment of dividends, and any amount that may ultimately be paid in connection with commitments and contingencies.

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

Sources and Uses of Cash

The following table presents the sources and uses of the Company's cash and cash equivalents for the years presented:

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Sources of Cash and Cash Equivalents:			
Net cash provided by continuing operating activities	$ 3,777	$ 2,428	$ 2,453
Proceeds from Altus transaction	628	—	—
Proceeds from asset divestitures, net of cash divested	138	1,419	134
Fixed-rate debt borrowings	992	—	—
Other	—	—	148
	5,535	3,847	2,735
Uses of Cash and Cash Equivalents:			
Capital expenditures(1)	$ 3,771	$ 2,582	$ 1,768
Leasehold and property acquisitions	133	178	181
Joint venture equity interest	91	—	—
Payments on fixed-rate debt	1,370	70	181
Dividends paid	382	380	379
Distributions to noncontrolling interest - Egypt	345	265	293
Shares repurchased	305	—	—
Other	92	81	23
	6,489	3,556	2,825
Increase (decrease) in cash and cash equivalents	$ (954)	$ 291	$ (90)

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

Net Cash Provided by Continuing Operating Activities

Operating cash flows are the Company's primary source of capital and liquidity and are impacted, both in the short-term and the long-term, by volatile oil and natural gas prices. The factors that determine operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation (ARO) accretion, exploratory dry hole expense, asset impairments, and deferred income tax expense.

Net cash provided by continuing operating activities for 2018 totaled $3.8 billion, up $1.3 billion from 2017. The increase primarily reflects higher commodity prices during 2018 compared to 2017.

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

Altus Transaction and Asset Divestitures

In November 2018, Apache and KAAC completed a previously announced transaction to create a pure-play, Permian Basin to Gulf Coast midstream C-corporation. Upon close, KAAC changed its name to Altus Midstream Company (ALTM) and contributed approximately $628 million of cash, net of transaction expenses, into its then wholly-owned subsidiary Altus Midstream LP. Apache contributed its Alpine High midstream assets into Altus Midstream LP in exchange for an approximate 79 percent ownership interest in ALTM and Altus Midstream LP (collectively, Altus). Apache fully consolidates the assets and liabilities of Altus. Cash from the Altus transaction and future ALTM and/or Altus Midstream LP financing activities are expected to fund future development of the Altus assets.

Also during 2018, 2017, and 2016, Apache recorded proceeds from divestitures totaling $138 million, $1.4 billion, and $134 million, respectively. For information regarding the Company's acquisitions and divestitures, please see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Fixed-Rate Debt Borrowings

In August 2018, Apache closed an offering of $1.0 billion in aggregate principal amount of senior unsecured 4.375% notes due October 15, 2028. The notes are redeemable at any time, in whole or in part, at Apache's option, subject to a make-whole premium. The net proceeds from the sale of the notes of $992 million were used to purchase certain outstanding notes in cash tender offers, repay notes that matured in September 2018, and for general corporate purposes.

Capital Expenditures and Equity Interest

During 2018, 2017, and 2016, capital spending for exploration and development (E&D) activities totaled $3.2 billion, $2.1 billion, and $1.6 billion, respectively. Apache's E&D capital spending was focused primarily in its North American onshore regions. Apache's investment in gas gathering, transmission, and processing (GTP) facilities totaled $581 million, $530 million, and $158 million during 2018, 2017, and 2016, respectively.

GTP expenditures over the past three years are nearly all comprised of investments in midstream infrastructure for the Alpine High play, which were subsequently contributed to Altus Midstream LP upon closing of the Altus transaction.

Apache also completed leasehold and property acquisitions for cash totaling $133 million, $178 million, and $181 million in 2018, 2017, and 2016, respectively. Acquisition investments continued to focus on adding new leasehold positions to our North American onshore portfolio.

On December 19, 2018, Altus Midstream LP exercised its option to acquire a 15 percent equity interest in Gulf Coast Express Pipeline LLC (GCX), a Delaware limited liability company, for total cash consideration of $91 million. GCX is a long-haul natural gas pipeline that is expected to be operational and in-service in the fourth quarter of 2019. Apache will consolidate this joint venture equity interest through ALTM.

Payments on Fixed-Rate Debt

In August 2018, the Company closed cash tender offers for certain outstanding notes. Apache accepted for purchase $731 million aggregate principal amount of notes for approximately $828 million, which included principal, the discount to par, and an early tender premium totaling $820 million, as well as accrued and unpaid interest of $8 million. The Company recorded a net loss of $94 million on extinguishment of debt, including $5 million of unamortized debt issuance costs and discount, in connection with the note purchases. Apache also made repayments of current year note maturities totaling $550 million during 2018.

Dividends

The Company has paid cash dividends on its common stock for 54 consecutive years through 2018. Future dividend payments will depend on the Company's level of earnings, financial requirements, and other relevant factors. Common stock dividends paid during 2018 totaled $382 million, compared with $380 million in 2017 and $379 million in 2016.

Egypt Noncontrolling Interest

Sinopec International Petroleum Exploration and Production Corporation (Sinopec) holds a one-third minority participation interest in Apache's oil and gas business in Egypt. Apache made cash distributions totaling $345 million, $265 million, and $293 million to Sinopec in 2018, 2017, and 2016, respectively.

Shares Repurchased

In 2013 and 2014, Apache's Board of Directors authorized the purchase of up to 40 million shares of the Company's common stock. Shares may be purchased either in the open market or through privately negotiated transactions. The Company initiated the buyback program on June 10, 2013, and through December 31, 2018, had repurchased a total of 40 million shares at an average price of $79.18 per share. During 2018, the Company repurchased a total of 7.8 million shares at an average price of $38.99 per share. During the fourth quarter of 2018, the Company's Board of Directors authorized the purchase of up to 40 million additional shares of the Company's common stock. The Company is not obligated to acquire any specific number of shares.

Liquidity

	At December 31,	
	2018	2017
	(In millions)	
Cash and cash equivalents	$ 714	$ 1,668
Total debt	8,204	8,484
Equity	8,812	8,791
Available committed borrowing capacity	3,857	3,500
Available committed borrowing capacity - Altus	450	—

Cash and Cash Equivalents

At December 31, 2018, Apache had $714 million in cash and cash equivalents, of which approximately $450 million was held by Altus. The majority of the cash is invested in highly liquid, investment-grade instruments with maturities of three months or less at the time of purchase.

Debt

At December 31, 2018, outstanding debt, which consisted of notes and debentures, totaled $8.2 billion, of which, $150 million matures in 2019, $393 million matures in 2021, $687 million matures in 2022, and the remaining matures in years 2023 through 2096. At December 31, 2018, $150 million of 7.625% senior notes due July 1, 2019 is classified as current debt on the consolidated balance sheet.

On August 23, 2018, Apache closed an offering of $1.0 billion in aggregate principal amount of senior unsecured 4.375% notes due October 15, 2028. The notes are redeemable at any time, in whole or in part, at Apache's option, subject to a make-whole premium. The net proceeds from the sale of the notes of $992 million were used to purchase certain outstanding notes in cash tender offers, repay notes that matured in September 2018, and for general corporate purposes.

In August 2017, the Company assumed the obligations of Apache Finance Canada Corporation (AFCC) in respect of $300 million 7.75% notes due in 2029, which AFCC issued and the Company guaranteed pursuant to the governing indenture. The assumption was permitted by the indenture and effected pursuant to a supplemental indenture thereto. As a result of the assumption, the Company is the obligor under the notes and indenture, and AFCC is released from its obligations thereunder. The $300 million 7.75% notes historically have been included in the Company's long-term debt; accordingly, the assumption did not change the Company's long-term debt or total debt.

Available Credit Facilities

In March 2018, Apache entered into a revolving credit facility that matures in March 2023 (subject to Apache's two, one-year extension options) with commitments totaling $4.0 billion. Apache can increase commitments up to $5.0 billion by adding new lenders or obtaining the consent of any increasing existing lenders. The facility includes a letter of credit subfacility of up to $3.0 billion, of which $2.08 billion was committed as of December 31, 2018. The facility is for general corporate purposes and committed borrowing capacity fully supports Apache's commercial paper program. Letters of credit are available for security needs, including in respect of abandonment obligations assumed in various North Sea acquisitions. As of December 31, 2018, letters of credit aggregating approximately £112.5 million and no borrowings were outstanding under this facility. In February 2019, £109.4 million of these outstanding letters of credit no longer were required and were terminated.

At Apache's option, the interest rate per annum for borrowings under the 2018 facility is either a base rate, as defined, plus a margin, or the London Inter-bank Offered Rate (LIBOR), plus a margin. Apache also pays quarterly a facility fee at a per annum rate on total commitments. The margins and the facility fee vary based upon Apache's senior long-term debt rating. At December 31, 2018, the base rate margin was 0.075 percent, the LIBOR margin was 1.075 percent, and the facility fee was 0.175 percent. A commission is payable quarterly to lenders on the face amount of each outstanding letter of credit at a per annum rate equal to the LIBOR margin then in effect. Customary letter of credit fronting fees and other charges are payable to issuing banks.

The financial covenants of the 2018 credit facility require Apache to maintain an adjusted debt-to-capital ratio of not greater than 60 percent at the end of any fiscal quarter. For purposes of this calculation, capital excludes the effects of non-cash write-downs, impairments, and related charges occurring after June 30, 2015. At December 31, 2018, Apache’s debt-to-capital ratio as calculated under the credit facility was 30 percent.

The 2018 facility's negative covenants restrict the ability of Apache and its subsidiaries to create liens securing debt on hydrocarbon-related assets, with exceptions for liens typically arising in the oil and gas industry; liens securing debt incurred to finance the acquisition, construction, improvement, or capital lease of assets, provided that such debt, when incurred, does not exceed the subject purchase price and costs, as applicable, and related expenses; liens on subsidiary assets located outside of the United States and Canada; and liens arising as a matter of law, such as tax and mechanics' liens. Apache also may incur liens on assets if debt secured thereby does not exceed 15 percent of Apache's consolidated net tangible assets, or approximately $2.9 billion as of December 31, 2018. Negative covenants also restrict Apache's ability to merge with another entity unless it is the surviving entity, dispose of substantially all of its assets, and guarantee debt of non-consolidated entities in excess of the stated threshold.

In November 2018, Altus Midstream LP, an indirectly controlled subsidiary of Apache, entered into a revolving credit facility for general corporate purposes that matures in November 2023 (subject to Altus Midstream LP's two, one-year extension options). The agreement for this facility provides aggregate commitments from a syndicate of banks of $450 million until (i) the consolidated net income of Altus Midstream LP and its restricted subsidiaries, as adjusted pursuant to the agreement, for three consecutive calendar months equals or exceeds $175 million on an annualized basis and (ii) Altus Midstream LP has raised at least $250 million of additional capital (such period, the "Initial Period"). Following the Initial Period, the aggregate commitments equal $800 million. All aggregate commitments include a letter of credit subfacility of up to $100 million and a swingline loan subfacility of up to $100 million. After the Initial Period, Altus Midstream LP may increase commitments up to an aggregate $1.5 billion by adding new lenders or obtaining the consent of any increasing existing lenders. As of December 31, 2018, no borrowings or letters of credit were outstanding under this facility.

The Altus Midstream LP credit facility is unsecured and is not guaranteed by Apache or any of Apache's other subsidiaries.

There are no clauses in either the agreement for Apache's 2018 credit facility or for Altus Midstream LP's 2018 credit facility that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes. These agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, each agreement allows the lenders to accelerate payment maturity and terminate lending and issuance commitments for nonpayment and other breaches, and if a borrower or any of its subsidiaries defaults on other indebtedness in excess of the stated threshold, is insolvent, or has any unpaid, non-appealable judgment against it for payment of money in excess of the stated threshold. Lenders may also accelerate payment maturity and terminate lending and issuance commitments under the applicable agreement if Apache or Altus Midstream LP, as applicable, undergoes a specified change in control or any borrower has specified pension plan liabilities in excess of the stated threshold. Each of Apache and Altus Midstream LP was in compliance with the terms of its 2018 credit facility as of December 31, 2018.

There is no assurance that the financial condition of banks with lending commitments to Apache or Altus Midstream LP will not deteriorate. We closely monitor the ratings of the banks in our bank groups. Having large bank groups allows the Company to mitigate the potential impact of any bank's failure to honor its lending commitment.

Commercial Paper Program

As of December 31, 2018, Apache has available a $3.5 billion commercial paper program which, subject to market availability, facilitates Apache borrowing funds for up to 270 days at competitive interest rates. The commercial paper program is fully supported by available borrowing capacity under Apache's 2018 $4.0 billion committed credit facility. If Apache is unable to issue commercial paper following a significant credit downgrade or dislocation in the market, Apache's 2018 committed credit facility, which matures in 2023, is available as a 100 percent backstop. As of December 31, 2018, Apache had no borrowings under its commercial paper program.

Off-Balance Sheet Arrangements

Apache enters into customary agreements in the oil and gas industry for drilling rig commitments, firm transportation agreements, and other obligations as described below in "Contractual Obligations" in this Item 7. Other than the off-balance sheet arrangements described herein, Apache does not have any off-balance sheet arrangements with unconsolidated entities that are reasonably likely to materially affect our liquidity or capital resource positions.

Contractual Obligations

The following table summarizes the Company's contractual obligations as of December 31, 2018. For additional information regarding these obligations, please see Note 7—Debt and Note 9—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Contractual Obligations(1)	Note Reference	Total	2019	2020-2021	2022-2023	2024 & Beyond
	(In millions)					
On-Balance Sheet:						
Debt, at face value	Note 7	$8,299	$150	$ 393	$ 1,090	$ 6,666
Interest payments	Note 7	7,193	407	782	722	5,282
Capital lease(2)	Note 9	40	1	3	4	32
Off-Balance Sheet:						
Drilling rigs(3)	Note 9	172	102	69	1	—
Purchase obligations(4)	Note 9	2,323	220	427	445	1,231
Operating lease obligations(5)	Note 9	220	61	64	53	42
Total Contractual Obligations		$18,247	$941	$ 1,738	$ 2,315	$ 13,253

(1) This table does not include the Company's liability for dismantlement, abandonment, and restoration costs of oil and gas properties or pension or postretirement benefit obligations. For additional information regarding these liabilities, please see Notes 6 and 10, respectively, in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

(2) This represents the Company's capital lease obligation related to its Midland, Texas office building. The imputed interest rate necessary to reduce the net minimum lease payments to present value of the lease term is 4.4 percent or $16 million as of December 31, 2018.

(3) Payments associated with the drilling of exploratory wells and development wells net of amounts billed to partners will be capitalized as a component of oil and gas properties, and either depreciated, impaired, or written off as exploration expense.

(4) Amounts represent any agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, drilling work program commitments, and agreements to secure capacity rights on third-party pipelines. Includes amounts related to firm transportation capacity on the Gulf Coast Express Pipeline Project (GCX Project), expected to be in service in the fourth quarter of 2019, and the Permian Highway Pipeline Project, expected to be in service in the fourth quarter of 2020 (refer to Delivery Commitments disclosure in Part I, Items 1 and 2 of this Annual Report on Form 10-K for more information regarding fixed sales contracts related to these pipelines). Amounts exclude certain product purchase obligations related to marketing and trading activities for which there are no minimum purchase requirements or the amounts are not fixed or determinable.

(5) Amounts include long-term lease payments for office space, aircraft, supply and standby vessels, land leases, and equipment related to exploration, development, and production activities.

As further described above under "Capital and Operational Outlook," Altus Midstream LP and/or its subsidiaries have the right, but not the obligation, to exercise options to acquire equity interest in third-party joint venture pipelines. Upon exercising each individual option, Altus Midstream LP and/or its subsidiaries may be required to fund future capital expenditures for its equity interest share in the development of the pipeline as referenced. In December 2018, Altus Midstream LP exercised its option for a 15 percent equity interest in the GCX Pipeline and estimates it will incur approximately $175 million of additional capital contributions during 2019 for its associated interest with the remaining construction costs.

Apache is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. Apache's management believes that it has adequately reserved for its contingent obligations, including approximately $4 million for environmental remediation and approximately $35 million for various contingent legal liabilities. For a detailed discussion of the Company's environmental and legal contingencies, please see Note 9—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

In addition to our recorded environmental and legal liabilities, we have potential exposure to future obligations related to divested properties. Apache has divested various leases, wells, and facilities located in the Gulf of Mexico where the purchasers typically assume all obligations to plug, abandon, and decommission the associated wells, structures, and facilities acquired. One or more of the counterparties in these transactions could, either as a result of the severe decline in oil and natural gas prices or other factors related to the historical or future operations of their respective businesses, face financial problems that may have a significant impact on their solvency and ability to continue as a going concern. If a purchaser of our Gulf of Mexico assets becomes the subject of a case or proceeding under relevant insolvency laws or otherwise fails to perform required abandonment obligations, Apache could be required to perform such actions under applicable federal laws and regulations. In such event, we may be forced to use available cash to cover the costs of such liabilities and obligations should they arise.

With respect to oil and gas operations in the Gulf of Mexico, the Bureau of Ocean Energy Management (BOEM) has issued a Notice to Lessees (NTL No. 2016-N01) significantly revising the obligations of companies operating in the Gulf of Mexico to provide supplemental assurances of performance with respect to plugging, abandonment, and decommissioning obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. While requirements under the NTL have not yet been fully implemented by BOEM, the NTL will likely require that Apache provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to Apache's current ownership interests in various Gulf of Mexico leases. We are working closely with BOEM to make arrangements for the provision of such additional required security, if such security becomes necessary under the NTL. Additionally, we are not able to predict the effect that these changes might have on counterparties to which Apache has sold Gulf of Mexico assets or with whom Apache has joint ownership. Such changes could cause the bonding obligations of such parties to increase substantially, thereby causing a significant impact on the counterparties' solvency and ability to continue as a going concern.

Insurance Program

We maintain insurance policies that include coverage for physical damage to our assets, general liabilities, workers' compensation, employers' liability, sudden and accidental pollution, and other risks. Our insurance coverage is subject to deductibles or retentions that we must satisfy prior to recovering on insurance. Additionally, our insurance is subject to policy exclusions and limitations. There is no assurance that our insurance will adequately protect us against liability from all potential consequences and damages.

Our current insurance policies covering physical damage to our assets provide up to $1 billion in coverage per occurrence. These policies also provide sudden and accidental pollution coverage. Coverage for Gulf of Mexico named windstorms is excluded from this coverage.

Our current insurance policies covering general liabilities provide approximately $500 million in coverage, scaled to Apache's interest. Our service agreements, including drilling contracts, generally indemnify Apache for injuries and death of the service provider's employees as well as subcontractors hired by the service provider.

Apache purchases multi-year political risk insurance from the Overseas Private Investment Corporation (OPIC) and highly-rated insurers covering a portion of its investments in Egypt for losses arising from confiscation, nationalization, and expropriation risks. The Islamic Corporation for the Insurance of Investment and Export Credit (ICIEC, an agency of the Islamic Development Bank) reinsures OPIC. In the aggregate, these insurance policies provide up to $750 million of coverage to Apache, subject to policy terms and conditions and a retention of approximately $1 billion.

Apache has an additional insurance policy with OPIC, which, subject to policy terms and conditions, provides up to $300 million of coverage through 2024 for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent Apache from exporting our share of production. The Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, provides $150 million in reinsurance to OPIC.

Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable.

Critical Accounting Policies and Estimates

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

Reserves Estimates

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

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

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. A material adverse change in the estimated volumes of reserves could result in property impairments. Finally, 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 the production, 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.

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

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill.

The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company’s assets and liabilities and tax-related carryforwards at the merger date, although such estimates may change in the future as additional information becomes known. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed relative to the total acquisition cost.

When estimating the fair values of assets acquired and liabilities assumed, the Company must apply various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, the Company prepares estimates of crude oil and natural gas reserves as described above in “Reserve Estimates” of this Item 7. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future.

Oil and Gas Exploration Costs

Apache accounts for its exploration and production activities using the successful efforts method of accounting. Costs of acquiring unproved and proved oil and gas leasehold acreage are capitalized. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are also capitalized. Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs associated with drilling an exploratory well are initially capitalized, or suspended, pending a determination as to whether proved reserves have been found. On a quarterly basis, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities and determines whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are recorded as dry hole expense and reported in exploration expense in the statement of consolidated operations. Otherwise, the costs of exploratory wells remain capitalized.

Long-Lived Assets

Long-lived assets used in operations, including proved oil and gas properties, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach.

Under the income approach, the fair value of each asset group is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, the success of future exploration for and development of unproved reserves, discount rates, and other variables. Key assumptions used in developing a discounted cash flow model described above include estimated quantities of crude oil and natural gas reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative, and capital costs adjusted for inflation. We discount the resulting future cash flows using a discount rate believed to be consistent with those applied by market participants.

To assess the reasonableness of our fair value estimate, when available we use a market approach to compare the fair value to similar assets. This requires management to make certain judgments about the selection of comparable assets, recent comparable asset transactions, and transaction premiums.

Although we base the fair value estimate of each asset group on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the asset group, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an additional impairment of long-lived assets in future periods.

Over the past several years, the Company has experienced substantial volatility in commodity prices, which impacted our future development plans and operating cash flows. As such, we recorded impairments of certain proved oil and gas properties and gathering, transmission, and processing facilities in 2018 and 2016. For discussion of these impairments, see “Fair Value Measurements” of Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Asset Retirement Obligation (ARO)

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Apache’s removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms in the North Sea and Gulf of Mexico. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with Apache’s oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. 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. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Income Taxes

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

The Company regularly assesses and, if required, establishes accruals for uncertain tax positions that could result from assessments of additional tax by taxing jurisdictions in countries where the Company operates. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. These accruals for uncertain tax positions are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, case law, and any new legislation. The Company believes that its accruals for uncertain tax positions are adequate in relation to the potential for any additional tax assessments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Risk

The Company’s revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas and NGLs, which have historically been very volatile because of unpredictable events such as economic growth or retraction, weather and political climate. The Company’s average crude oil realizations have increased 27 percent to $65.30 per barrel in 2018 from $51.46 per barrel in 2017. The Company’s average natural gas price realizations have decreased 5 percent to $2.61 per Mcf in 2018 from $2.74 per Mcf in 2017. Based on average daily production for 2018, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $90 million, 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 $35 million.

Apache periodically enters into derivative positions on a portion of its projected oil and natural gas production through a variety of financial and physical arrangements intended to manage fluctuations in cash flows resulting from changes in commodity prices. Apache periodically uses futures contracts, swaps, and options to mitigate commodity price risk. Apache does not hold or issue derivative instruments for trading purposes. As of December 31, 2018, the Company had open natural gas derivatives in an asset position with a fair value of $69 million. A 10 percent increase in gas prices would increase the asset by approximately $2 million, while a 10 percent decrease in prices would decrease the asset by approximately $1 million. As of December 31, 2018, the Company had open oil derivatives to protect basis differentials on Permian Basin production. These derivatives were in a liability position with a fair value of $25 million. A 10 percent increase in oil prices would decrease the liability by approximately $4 million, while a 10 percent decrease in prices would increase the liability by approximately $4 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2018. See Note 4—Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K for notional volumes and terms with the Company’s derivative contracts.

Interest Rate Risk

At December 31, 2018, Apache had approximately $8.1 billion of long-term debt (excluding capital lease and other obligations) outstanding, all of which was fixed-rate debt, with a weighted average interest rate of 4.89 percent. Although near-term changes in interest rates may affect the fair value of Apache’s fixed-rate debt, they do not expose the Company to the risk of earnings or cash flow loss associated with that debt. Apache is also exposed to interest rate risk related to its interest-bearing cash and cash equivalents balances and amounts outstanding under its credit facilities. As of December 31, 2018, the Company’s cash and cash equivalents totaled approximately $714 million, approximately 98 percent of which was invested in money market funds and short-term investments with major financial institutions. A change in the interest rate applicable to the Company’s short-term investments would have a de minimis impact on earnings and cash flows but could impact interest costs associated with future debt issuances or any future borrowings under its revolving credit facility and/or money market lines of credit. Apache currently has no interest rate derivative instruments outstanding. However, the Company may enter into interest rate derivative instruments in the future if it determines that it is necessary to invest in such instruments in order to mitigate its interest rate risk.

Foreign Currency Risk

The Company’s cash activities relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. Our North Sea production is sold under U.S. dollar contracts, and the majority of costs incurred are paid in British pounds. In Egypt, substantially all oil and gas production is sold under U.S. dollar contracts, and the majority of the costs incurred are denominated in U.S. dollars. Revenue and disbursement transactions denominated in British pounds are converted to U.S. dollar equivalents based on the average exchange

rates during the period.
Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Currency gains and losses are included as either a component of “Other” under “Revenues and Other” or, as is the case when we re-measure our foreign tax liabilities, as a component of the Company’s provision for income tax expense on the statement of consolidated operations. A 10 percent strengthening or weakening of the British pound against the U.S. dollar as of December 31, 2018, would result in a foreign currency net loss or gain, respectively, of approximately $1 million.

We have outstanding foreign exchange contracts with a total notional amount of £150 million that are used to reduce our exposure to fluctuating foreign exchange rates for the British pound. A 10 percent strengthening of the British pound against the U.S. dollar would result in a foreign currency net gain of $6 million, while a 10 percent weakening of the British pound against the U.S. dollar would result in a loss of $3 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements and supplementary financial information required to be filed under this Item 8 are presented on pages F-1 through F-60 in Part IV, Item 15 of this Form 10-K and are incorporated herein by reference.

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

The financial statements for the fiscal years ended December 31, 2018, 2017, and 2016, 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 Company's Chief Executive Officer and President, in his capacity as principal executive officer, and Stephen J. Riney, the Company's Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2018, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the Commission's rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure. We made no changes in internal controls over financial reporting during the quarter ending December 31, 2018, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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

Management's Annual Report on Internal Control Over Financial Reporting; Attestation Report of the Registered Public Accounting Firm

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 F-1 in Part IV, Item 15 of this Form 10-K.

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

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2018, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information set forth under the captions “Nominees for Election as Directors,” “Continuing Directors,” “Executive Officers of the Company,” and “Securities Ownership and Principal Holders” in the proxy statement relating to the Company’s 2019 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, we are required to adopt a code of business conduct and ethics for our directors, officers, and employees. In February 2004, the Board of Directors adopted the Code of Business Conduct 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 the Company’s Code of Conduct on the Governance page of the Company’s website at www.apachecorp.com. Any shareholder who so requests may obtain a printed copy of the Code of Conduct by submitting a request to the Company’s corporate secretary at the address on the cover of this Form 10-K. Changes in and waivers to the Code of Conduct for the Company’s directors, chief executive officer and certain senior financial officers will be posted on the Company’s website within five business days and maintained for at least 12 months. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

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

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

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

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

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information set forth under the caption “Ratification of Appointment of Independent Auditors” in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. Financial Statements

2. Financial Statement Schedules

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

3. Exhibits

See Index to Exhibits of this report.

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, hereunto duly authorized.

APACHE CORPORATION

/s/ John J. Christmann IV
John J. Christmann IV
Chief Executive Officer and President

Dated: February 28, 2019

POWER OF ATTORNEY

The officers and directors of Apache Corporation, 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.

Name	Title	Date
/s/ John J. Christmann IV John J. Christmann IV	Director, Chief Executive Officer, and President (principal executive officer)	February 28, 2019
/s/ Stephen J. Riney Stephen J. Riney	Executive Vice President and Chief Financial Officer (principal financial officer)	February 28, 2019
/s/ Rebecca A. Hoyt Rebecca A. Hoyt	Senior Vice President, Chief Accounting Officer, and Controller (principal accounting officer)	February 28, 2019
/s/ Annell R. Bay Annell R. Bay	Director	February 28, 2019
/s/ Chansoo Joung Chansoo Joung	Director	February 28, 2019
/s/ Rene R. Joyce Rene R. Joyce	Director	February 28, 2019
/s/ George D. Lawrence George D. Lawrence	Director	February 28, 2019
/s/ John E. Lowe John E. Lowe	Director, Non-Executive Chairman of the Board	February 28, 2019
/s/ William C. Montgomery William C. Montgomery	Director	February 28, 2019
/s/ Amy H. Nelson Amy H. Nelson	Director	February 28, 2019
/s/ Daniel W. Rabun Daniel W. Rabun	Director	February 28, 2019
/s/ Peter A. Ragauss Peter A. Ragauss	Director	February 28, 2019

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REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. 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 Company maintained effective internal control over financial reporting as of December 31, 2018.

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

/s/ John J. Christmann IV
Chief Executive Officer and President
(principal executive officer)

/s/ Stephen J. Riney
Executive Vice President and Chief Financial Officer
(principal financial officer)

/s/ Rebecca A. Hoyt
Senior Vice President, Chief Accounting Officer and Controller
(principal accounting officer)
Houston, Texas
February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Apache Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Apache Corporation and subsidiaries' internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Apache Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related statements of consolidated operations, comprehensive income (loss), cash flows and changes in equity for each of the three years in the period ended December 31, 2018, and the related notes and our report dated February 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Apache Corporation:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Apache Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, the related statements of consolidated operations, comprehensive income (loss), cash flows, and changes in equity for each of the three years in the period ended December 31, 2018, 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 Company at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company 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. 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 Company's auditor since 2002.

Houston, Texas

February 28, 2019

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil and gas production revenues:			
Oil revenues	$ 5,846	$ 4,598	$ 4,172
Natural gas revenues	919	959	967
Natural gas liquids revenues	583	330	228
	7,348	5,887	5,367
Derivative instrument losses, net	(17)	(135)	—
Gain on divestitures	23	627	21
Other	70	44	(34)
	7,424	6,423	5,354
OPERATING EXPENSES:			
Lease operating expenses	1,439	1,384	1,494
Gathering, transmission, and processing	348	195	200
Taxes other than income	215	151	126
Exploration	503	549	473
General and administrative	431	395	410
Transaction, reorganization, and separation	28	16	39
Depreciation, depletion, and amortization	2,405	2,280	2,618
Asset retirement obligation accretion	108	130	156
Impairments	511	8	1,103
Financing costs, net	478	397	417
	6,466	5,505	7,036
NET INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	958	918	(1,682)
Current income tax provision	894	595	391
Deferred income tax benefit	(222)	(1,180)	(833)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS INCLUDING NONCONTROLLING INTEREST	286	1,503	(1,240)
Net loss from discontinued operations, net of tax	—	—	(33)
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTEREST	286	1,503	(1,273)
Net income attributable to noncontrolling interest - Egypt	245	199	132
Net income attributable to noncontrolling interest - Altus	1	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 40	$ 1,304	$ (1,405)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS:			
Net income (loss) from continuing operations attributable to common shareholders	$ 40	$ 1,304	$ (1,372)
Net loss from discontinued operations	—	—	(33)
Net income (loss) attributable to common shareholders	$ 40	$ 1,304	$ (1,405)
NET INCOME (LOSS) PER COMMON SHARE:			
Basic net income (loss) from continuing operations per share	$ 0.11	$ 3.42	$ (3.62)
Basic net loss from discontinued operations per share	—	—	(0.09)
Basic net income (loss) per share	$ 0.11	$ 3.42	$ (3.71)
DILUTED NET INCOME (LOSS) PER COMMON SHARE:			

Diluted net income (loss) from continuing operations per share	$ 0.11	$ 3.41	$ (3.62)
Diluted net loss from discontinued operations per share	—	—	(0.09)
Diluted net income (loss) per share	$ 0.11	$ 3.41	$ (3.71)
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	382	381	379
Diluted	384	383	379
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.00	$ 1.00	$ 1.00

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

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTEREST	$ 286	$ 1,503	$ (1,273)
OTHER COMPREHENSIVE INCOME (LOSS):			
Pension and postretirement benefit plan, net of tax	—	7	7
Currency translation adjustment	—	109	—
	—	116	7
COMPREHENSIVE INCOME (LOSS) INCLUDING NONCONTROLLING INTEREST	286	1,619	(1,266)
Comprehensive income attributable to noncontrolling interest - Egypt	245	199	132
Comprehensive income attributable to noncontrolling interest - Altus	1	—	—
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 40	$ 1,420	$ (1,398)

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

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APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2018	2017	2016
	(In millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss) including noncontrolling interest	$286	$1,503	$(1,273)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Loss from discontinued operations	—	—	33
Unrealized derivative instrument losses (gains), net	(103)	59	—
Gain on divestitures	(23)	(627)	(21)
Exploratory dry hole expense and unproved leasehold impairments	351	429	353
Depreciation, depletion, and amortization	2,405	2,280	2,618
Asset retirement obligation accretion	108	130	156
Impairments	511	8	1,103
Benefit from deferred income taxes	(222)	(1,180)	(833)
Loss from extinguishment of debt	94	1	1
Other	125	145	163
Changes in operating assets and liabilities:			
Receivables	150	(270)	126
Inventories	(6)	32	(27)
Drilling advances	(11)	(128)	91
Deferred charges and other	83	(58)	115
Accounts payable	77	63	(63)
Accrued expenses	5	4	(9)
Deferred credits and noncurrent liabilities	(53)	37	(80)
NET CASH PROVIDED BY CONTINUING OPERATING ACTIVITIES	3,777	2,428	2,453
NET CASH USED IN DISCONTINUED OPERATIONS	—	—	(23)
NET CASH PROVIDED BY OPERATING ACTIVITIES	3,777	2,428	2,430
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(3,190)	(2,052)	(1,610)
Additions to gas gathering, transmission, and processing facilities	(581)	(530)	(158)
Leasehold and property acquisitions	(133)	(178)	(181)
Joint venture equity interest	(91)	—	—
Proceeds from sale of Canadian assets, net of cash divested	—	661	—
Proceeds from sale of oil and gas properties, other	138	758	134
Other, net	(87)	(75)	155
NET CASH USED IN INVESTING ACTIVITIES	(3,944)	(1,416)	(1,660)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Fixed rate debt borrowings	992	—	—
Payments on fixed-rate debt	(1,370)	(70)	(181)
Proceeds from Altus transaction	628	—	—
Distributions to noncontrolling interest - Egypt	(345)	(265)	(293)
Dividends paid	(382)	(380)	(379)
Treasury stock activity, net	(305)	—	—
Other	(5)	(6)	(7)
NET CASH USED IN FINANCING ACTIVITIES	(787)	(721)	(860)

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(954)	291	(90)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,668	1,377	1,467
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$714	$1,668	$1,377
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$402	$405	$413
Income taxes paid, net of refunds	$867	$516	$305

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

APACHE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31,	
	2018	2017
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$714	$1,668
Receivables, net of allowance	1,194	1,345
Inventories	401	368
Drilling advances	218	207
Prepaid assets and other	160	137
	2,687	3,725
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of successful efforts accounting:		
Proved properties	42,345	