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

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.

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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.

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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 perfor