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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2021

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 **1-40144**

APA CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**86-1430562**
(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) (Zip Code)
Registrant's telephone number, including area code **(713) 296-6000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.625 par value	**APA**	**Nasdaq Global Select Market**

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an 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 ☒ 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2021	$	8,176,506,326
Number of shares of registrant's common stock outstanding as of January 31, 2022		346,776,379

Documents Incorporated By Reference

Portions of the registrant's definitive proxy statement relating to the registrant's 2022 annual meeting of stockholders are incorporated by reference in Part II and Part III of this Annual Report on Form 10-K.

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FORWARD-LOOKING STATEMENTS AND RISKS

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 (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical facts included or incorporated by reference in this Annual Report on Form 10-K, including, without limitation, statements regarding the Company’s 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 the Company’s examination of historical operating trends, the information that was used to prepare its estimate of proved reserves as of December 31, 2021, and other data in the Company’s 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,” “continue,” “seek,” “guidance,” “might,” “outlook,” “possibly,” “potential,” “prospect,” “should,” “would,” or similar terminology, but the absence of these words does not mean that a statement is not forward looking. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable under the circumstances, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company’s expectations include, but are not limited to, its assumptions about:

- the scope, duration, and reoccurrence of any epidemics or pandemics (including, specifically, the coronavirus disease 2019 (COVID-19) pandemic and any related variants) and the actions taken by third parties, including, but not limited to, governmental authorities, customers, contractors, and suppliers, in response to such epidemics or pandemics;
- the mandate, availability, and effectiveness of vaccine programs and therapeutics related to the treatment of COVID-19;
- the market prices of oil, natural gas, natural gas liquids (NGLs), and other products or services;
- the Company’s 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 expenditures and other contractual obligations;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the availability of goods and services;
- the impact of political pressure and the influence of environmental groups and other stakeholders on decisions and policies related to the industries in which the Company and its affiliates operate;
- legislative, regulatory, or policy changes, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring, or water disposal;
- the Company’s performance on environmental, social, and governance measures;
- terrorism or cyberattacks;
- the occurrence of property acquisitions or divestitures;
- the integration of acquisitions;
- the Company’s ability to access the capital markets;
- market-related risks, such as general credit, liquidity, and interest-rate risks;
- the Company’s expectations with respect to the new operating structure implemented pursuant to the Holding Company Reorganization (as defined in the Notes to the Company’s Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K) and the associated disclosure implications; 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 Annual Report on Form 10-K.

Other factors or events that could cause the Company’s actual results to differ materially from the Company’s expectations may emerge from time to time, and it is not possible for the Company to predict all such factors or events. 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. All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. Except as required by law, the Company disclaims any obligation to update or revise these statements, whether based on changes in internal estimates or expectations, new information, future developments, 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 Annual Report on Form 10-K. As used herein:

"3-D" means three-dimensional.

"4-D" means four-dimensional.

"b/d" means barrels of oil or NGLs per day.

"bbl" or "bbls" means barrel or barrels of oil or NGLs.

"bcf" means billion cubic feet of natural gas.

"bcf/d" means one bcf per day.

"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 NGLs.

"LNG" means liquefied natural gas.

"Mb/d" means Mbbls per day.

"Mbbls" means thousand barrels of oil or NGLs.

"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 NGLs.

"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 the United States Securities and Exchange Commission.

"Tcf" means trillion cubic feet of natural gas.

"U.K." means United Kingdom.

"U.S." means United States.

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

References to “APA,” the “Company,” “we,” “us,” and “our” refer to APA Corporation and its consolidated subsidiaries, including Apache Corporation, unless otherwise specifically stated. References to “Apache” refer to Apache Corporation, the Company’s wholly owned subsidiary, and its consolidated subsidiaries, unless otherwise specifically stated.

PART I

ITEMS 1 and 2. ***BUSINESS AND PROPERTIES***

GENERAL

APA Corporation (APA or the Company), is an independent energy company that explores for, develops, and produces natural gas, crude oil, and NGLs. The Company's upstream business 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). APA also has active exploration and appraisal operations ongoing in Suriname, as well as interests in other international locations that may, over time, result in reportable discoveries and development opportunities. The Company's midstream business (Altus Midstream) is operated by Altus Midstream Company (Nasdaq: ALTM) through its subsidiary Altus Midstream LP (collectively, Altus). Altus owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas.

On March 1, 2021, Apache Corporation completed a holding company reorganization (the Holding Company Reorganization), pursuant to which, Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares were automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe.

The Company's common stock, par value $0.625 per share, is listed on the Nasdaq. Through the Company's website, www.apacorp.com, you can access, free of charge, electronic copies of the charters of the committees of its board of directors (Board of Directors), other documents related to corporate governance (including the Code of Business Conduct and Ethics and APA's Corporate Governance Principles), and documents the Company files with the SEC, including the Company's 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 Exchange Act. Included in the Company's annual and quarterly reports are the certifications of its principal executive officer and its principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after the Company files such material with, or furnishes it to, the SEC. You may also request printed copies of the Company's corporate charter, bylaws, committee charters, or other governance documents free of charge by writing to the Company's corporate secretary at the address on the cover of this Annual Report on Form 10-K. The Company's reports filed with the SEC are made available on its website at www.sec.gov. From time to time, the Company also posts announcements, updates, and investor information on its website in addition to copies of all recent press releases. Information on the Company's 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.

Certain properties referred to herein may be held by subsidiaries of APA Corporation.

BUSINESS STRATEGY

OUR PURPOSE

APA believes energy underpins global progress, and the Company wants to be a part of the conversation and solution as society works to meet growing global demand for reliable and affordable energy. Today, the world faces a dual challenge: To meet growing demand for energy and to do so in a cleaner, more sustainable way. APA believes society can accomplish both, and strives to meet those challenges while creating value for all its stakeholders.

OUR VISION

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

OUR CORE VALUES

- Safety is not negotiable and will not be compromised.
- Conduct business with honesty and integrity.
- We derive benefit from the Earth and take our environmental responsibility seriously.

- Treat stakeholders with respect and dignity.
- Invest in our greatest asset: our people.
- Expect top performance and innovation.
- Seek relentless improvement in all facets.
- Drive to succeed with a sense of urgency.
- Foster a contrarian spirit.

APA maintains a diversified asset portfolio, including conventional and unconventional, onshore and offshore, exploration and production interests. In the U.S., APA operations are primarily focused in the Permian Basin of West Texas and Eastern New Mexico, with additional operations located in the Eagle Ford shale and Austin Chalk areas of Southeast Texas, offshore in the Gulf of Mexico, and along the Gulf Coast. Internationally, the Company has conventional onshore assets in Egypt's Western Desert, offshore assets on the U.K.'s Continental Shelf, an offshore appraisal and exploration program in Suriname, and an offshore exploration block in the Dominican Republic.

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, APA 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. Management actively reviews certain non-strategic assets for opportunities, which include potential monetization of legacy properties and other non-core leasehold positions.

During 2021, the Company made significant progress on key aspects of its portfolio. Specifically, the Company refreshed the economic foundation for its business in Egypt with the announcement of the ratification of a modernized production-sharing contract (PSC) with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation (EGPC). The new PSC consolidates the majority of the Company's gross acreage and production in Egypt into a single concession and refreshes existing development and exploration lease terms. The modernized PSC incentivizes increased investment and production growth and places Egypt at the top of many attractive investment opportunities in APA's global portfolio.

In October 2021, Altus Midstream Company (ALTM) announced that it will combine with privately owned BCP Raptor Holdco LP (BCP) in an all-stock transaction, and APA's ownership in ALTM will be reduced from approximately 79 percent to approximately 20 percent. Reducing APA's interest in Altus to a minority position will have a number of benefits to APA shareholders, including simplification of its financial reporting and enhanced comparability with its upstream-only peers, while maintaining a noncontrolling interest in future growth opportunities.

The global economy and the energy industry have been deeply impacted by the effects of the coronavirus disease 2019 (COVID-19) pandemic and related governmental actions. Uncertainty in the commodity and financial markets since early 2020 continue to impact oil supply and demand. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to maintain a balanced asset portfolio, including advancement of ongoing exploration and appraisal activities offshore Suriname; (2) to invest for long-term returns over production growth; and (3) to budget conservatively to generate cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and return of capital to its stakeholders. The Company continues to aggressively manage its cost structure regardless of the oil price environment and closely monitors hydrocarbon pricing fundamentals to reallocate capital as part of its ongoing planning process.

For a more in-depth discussion of the Company's 2021 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 Annual Report on Form 10-K.

BUSINESS OVERVIEW

The following business overview further describes the operations and activities for the Company's upstream exploration and production properties, by geographic region, and Altus Midstream.

UPSTREAM EXPLORATION AND PRODUCTION

Operating Areas

APA has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea. APA also has active exploration and appraisal operations ongoing in Suriname, as well as interests in other international locations that may, over time, result in reportable discoveries and development opportunities.

The following table sets out a brief comparative summary of certain key 2021 data for each of the Company's operating areas. Additional data and discussion are provided in Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report on 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	83.7	59 %	$ 3,277	617	68 %	102	102
Egypt[(1)]	41.9	30 %	2,085	197	21 %	54	39
North Sea[(2)]	16.0	11 %	1,136	99	11 %	6	4
Other International	—	—	—	—	—	4	—
Total	141.6	100 %	$ 6,498	913	100 %	166	145

(1) The Company's operations in Egypt, excluding the impacts of a one-third noncontrolling interest, contributed 22 percent of 2021 production and accounted for 16 percent of year-end estimated proved reserves.

(2) Sales volumes from the Company's North Sea assets for 2021 were 16.1 MMboe. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

United States

In 2021, the Company's U.S. upstream oil and gas operations contributed approximately 59 percent of production and 68 percent of estimated year-end proved reserves, consistent with prior years. APA has access to significant liquid hydrocarbons across its 3.8 million gross acres (1.8 million net acres) in the U.S., 75 percent of which are undeveloped.

The Company's U.S. assets are primarily located in the Permian Basin in West Texas and New Mexico, including the Permian sub-basins: Midland Basin, Central Basin Platform/Northwest Shelf, and Delaware Basin. Examples of shale plays being developed within these sub-basins include the Woodford, Barnett, Pennsylvanian, Cline, Wolfcamp, Bone Spring, and Spraberry. APA is one of the largest operators in the Permian Basin, operating approximately 6,000 gross oil and gas wells across its acreage, with additional interests in more than 3,000 non-operated wells. Of note, approximately six percent of the Company's net acreage position in the Permian Basin is on federal onshore lands. APA also has operations located in the Eagle Ford shale and Austin Chalk areas of Southeast Texas, offshore in the Gulf of Mexico, and along the Gulf Coast in South Texas and Louisiana.

Highlights of the Company's operations in the U.S. include:

- *Southern Midland Basin* APA holds approximately 332,000 gross acres (238,000 net acres) in the Southern Midland Basin. During 2021, the Company averaged one rig targeting oil plays in the Wolfcamp and Spraberry formations, drilling 49 gross development wells in this basin with a 100 percent success rate.
- *Delaware Basin* APA holds approximately 267,000 gross acres (134,000 net acres) in the Delaware Basin, including opportunities in the Bone Spring and other formations of Eastern New Mexico and bordering West Texas, and the Alpine High play in the Southern portion of the Permian Basin, primarily in Reeves County, Texas. During 2021, the Company focused on completing wells drilled from previous years and completed 27 gross development wells.
- *Legacy Assets* APA holds approximately 3.2 million gross acres (1.5 million net acres) in legacy properties, of which 1.1 million gross acres are in the offshore waters of the Gulf of Mexico. Legacy onshore properties are located primarily in the Eagle Ford shale and Austin Chalk areas of Southeast Texas. The Company participated in drilling 14 gross non-operated development wells in these areas during 2021. The Company also initiated a targeted drilling program on its Austin Chalk acreage where it will continue to evaluate and high-grade inventory opportunities. Consistent with the Company's broader portfolio management efforts, certain non-strategic leasehold positions on its legacy acreage holdings during the year were divested, primarily in the Central Basin Platform subbasin of the Permian Basin, and additional monetization opportunities are continuing to be evaluated.
- *New Venture Assets* APA separately has undeveloped acreage positions across several states where it intends to pursue exploration interests and potential development opportunities over time.
- During the fourth quarter of 2021, the Company announced that it has ended routine flaring in its U.S. onshore operations, achieving one of its announced 2021 environmental, social and governance (ESG) goals, three months ahead of schedule.

With the improvement in commodity prices, the Company is returning to a modest level of activity in the U.S. After halting all drilling and completion activity for most of 2020, in early 2021 the Company re-activated one rig in the Permian Basin and one rig in the Austin Chalk. A second rig was added in the Permian Basin in late June 2021. For 2022, the Company will continue to budget its capital program at levels to fund activity necessary to offset inherent declines in production and proved oil and natural gas reserves. Future rig activity levels and drilling targets will be dependent on the success of the Company's drilling program and its ability to add reserves economically.

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. APA strives to maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk. The Company predominantly sells its natural gas production within the U.S., including to U.S. LNG export facilities, although a portion may be sold to markets in Mexico.

APA primarily markets its U.S. crude oil production to integrated major oil companies, marketing and transportation companies, and refiners based on West Texas Intermediate (WTI) pricing indices (e.g. WTI Houston, West Texas Sour (WTS), or WTI Midland) and some predominately Brent related international pricing indices, adjusted for quality, transportation, and a market-reflective differential. The Company'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 an opportunity for higher than prevailing market prices.

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

U.S. Delivery Commitments The Company has long-term delivery commitments for natural gas and crude oil that require APA to deliver an average of 251 Bcf of natural gas per year for the period from 2022 through 2029 at variable, market-based pricing and deliver an average of 6.4 MMbbls of crude oil per year from 2022 through 2025 at variable, market-based pricing.

APA currently expects to fulfill its delivery commitments with production from its proved reserves, production from continued development and/or spot market purchases as necessary. APA may also enter into contractual arrangements to reduce its delivery commitments. The Company has not experienced any significant constraints in satisfying the committed quantities required by its delivery commitments.

For more information regarding the Company's commitments, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Contractual Obligations of this Annual Report on Form 10-K.

International

In 2021, international assets contributed 41 percent of APA's production and 50 percent of oil and gas revenues. Approximately 32 percent of estimated proved reserves at year-end were located outside the U.S.

APA has two international locations with ongoing development and production operations:

- Egypt, which includes onshore conventional assets located in Egypt's Western Desert; and
- the North Sea, which includes offshore assets based in the U.K.

The Company also has an active offshore exploration program and appraisal operations ongoing in Suriname and an offshore exploration block in the Dominican Republic.

Egypt APA has 26 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 2021, the Company held 5.3 million gross acres in Egypt in six separate concessions, but primarily held in a new, single concession that resulted from the ratification of a modernized production sharing contract (PSC) with the Egyptian government, as more fully described below. Development leases within concessions currently have expiration dates ranging from 1 to 20 years, with extensions possible for additional commercial discoveries or on a negotiated basis. Approximately 68 percent of the Company's gross acreage in Egypt is undeveloped, providing APA with considerable exploration and development opportunities for the future.

APA's Egypt operations are conducted pursuant to PSCs. Under the terms of the Company's PSCs, the Company is the contractor partner (Contractor) with Egyptian General Petroleum Corporation (EGPC) and 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 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 are 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 the Company's Egypt operations despite impacting the Company's production and reserves.

On December 27, 2021, the Company announced the ratification of a modernized PSC with EGPC having an effective date of April 1, 2021. The new PSC consolidates 98 percent of gross acreage and 90 percent of gross production into a single concession and refreshes the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool to provide improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all the Company's production covered under the new concession. The APA subsidiary that became the sole Contractor under the PSC is owned by an APA-operated joint venture owned two-thirds by the Company and one-third by Sinopec International Petroleum Exploration and Production Corporation (Sinopec).

The Company's estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country's share of reserves. Through the joint venture, Sinopec holds a one-third minority participation interest in the Company's oil and gas operations in Egypt. The Company's Egypt assets, including the one-third noncontrolling interest, contributed 30 percent of 2021 production and 21 percent of year-end estimated proved reserves. Excluding the impacts of the noncontrolling interest, Egypt contributed 22 percent of 2021 production and 16 percent of year-end estimated proved reserves.

In 2021, the Company drilled 30 gross development and 24 gross exploration wells in Egypt. A key component of the Company's success has been the ability to acquire and evaluate 3-D seismic surveys that enable the Company'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. The Company has completed seismic surveys covering over 3 million acres to date and continues to build and enhance its drilling inventory in Egypt, supplemented with recent seismic acquisitions and new play concept evaluations, on both new and existing acreage.

For 2022, the Company plans to increase activity to a 15 rig drilling program for the year and increase well completions by approximately three times compared to 2021 with a goal of growing gross oil production 13 to 15 percent.

North Sea The Company has interests in approximately 494,000 gross acres in the U.K. North Sea. These assets contributed 11 percent of the Company's 2021 production and approximately 11 percent of year-end estimated proved reserves.

The Company entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (Forties). Since acquiring Forties, the Company has actively invested in these assets 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 the Company acquired Mobil North Sea Limited, providing the Company with additional exploration and development opportunities in the North Sea 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. The Company 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 assets play a strategic role in APA's portfolio by providing competitive investment opportunities and potential reserve upside with high-impact exploration potential, near existing infrastructure.

During 2021, the Company averaged two rigs in the North Sea and drilled 4 gross development and two gross exploration wells. Production was significantly impacted by compressor downtime, extended platform turnaround work, and third-party outage during 2021.

In 2022, the expected capital program for the North Sea remains relatively unchanged from the prior year with one floating rig and one platform crew.

International Marketing The Company'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 sold and exported from one of two terminals on the Northern coast of Egypt. Oil production sold to EGPC is sold at prices related to the export market.

The Company's North Sea crude oil production is sold under term, entitlement volume contracts and spot variable volume contracts with a market-based index price plus a differential to capture the higher market value under each type of arrangement. Natural gas from the Beryl field is processed through the Scottish Area Gas Evacuation (SAGE) gas plant, operated by Ancala Midstream Acquisitions Limited. Natural 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, butane, and condensate are sold separately on a monthly entitlement basis at the Braefoot Bay terminal using index pricing less transportation.

Other Exploration

New Ventures APA's international 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.

In December 2019, the Company entered into a joint venture agreement with TotalEnergies (formerly Total S.A.) to explore and develop Block 58 offshore Suriname. The Company holds a 50 percent working interest in Block 58, which comprises approximately 1.4 million gross acres in water depths ranging from less than 100 meters to more than 2,100 meters. Starting in late 2019 and throughout 2020, the Company drilled the first three wells in the block, the Maka Central-1, Sapakara West-1, and Kwaskwasi-1, all of which successfully tested for the presence of hydrocarbons in multiple stacked targets in the upper Cretaceous-aged Campanian and Santonian intervals, encountering both oil and gas condensate.

In January 2021, APA and TotalEnergies announced the fourth consecutive discovery in Block 58 at Keskesi East-1, which confirmed oil in the eastern portion of the block. In accordance with the joint venture agreement, the Company transferred operatorship of Block 58 to TotalEnergies on January 1, 2021. TotalEnergies holds a 50 percent working interest in Block 58 as the operator, with an active appraisal and exploration program budgeted for 2022.

The Company is also a 45 percent working interest holder in Suriname on Block 53, where technical work completed in 2021 has led to the resumption of exploration activities. An exploration well is planned for early 2022 with partners CEPSA and Petronas who have a 25 percent and 30 percent working interest, respectively.

APA also holds an offshore exploration block in the Dominican Republic.

Drilling Statistics

Worldwide in 2021, APA drilled or participated in drilling 166 gross wells, with 145 wells (87 percent) completed as producers. Historically, APA'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, the Company's operations outside of the U.S. focus on a mix of exploration and development wells. In addition to wells completed, at year-end a number of wells had not yet reached completion: 53 gross (41.7 net) in the U.S., 22 gross (22.0 net) in Egypt, 1 gross (1 net) in the North Sea, and 1 gross (0.5 net) in Suriname.

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
2021									
United States	—	—	—	67.9	—	67.9	67.9	—	67.9
Egypt	10.0	14.0	24.0	28.5	1.0	29.5	38.5	15.0	53.5
North Sea	0.6	0.5	1.1	1.8	0.5	2.3	2.4	1.0	3.4
Other International	—	1.3	1.3	—	—	—	—	1.3	1.3
Total	10.6	15.8	26.4	98.2	1.5	99.7	108.8	17.3	126.1
2020									
United States	—	—	—	46.3	0.8	47.1	46.3	0.8	47.1
Egypt	17.7	7.0	24.7	35.7	—	35.7	53.4	7.0	60.4
North Sea	0.6	1.0	1.6	4.2	0.6	4.8	4.8	1.6	6.4
Other International	—	1.5	1.5	—	—	—	—	1.5	1.5
Total	18.3	9.5	27.8	86.2	1.4	87.6	104.5	10.9	115.4
2019									
United States	6.3	—	6.3	181.0	—	181.0	187.3	—	187.3
Egypt	8.5	13.5	22.0	37.2	1.5	38.7	45.7	15.0	60.7
North Sea	—	—	—	8.4	—	8.4	8.4	—	8.4
Total	14.8	13.5	28.3	226.6	1.5	228.1	241.4	15.0	256.4

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, 2021, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	8,862	5,309	957	663	9,819	5,972
Egypt	1,026	991	114	111	1,140	1,102
North Sea	164	121	13	8	177	129
Total	10,052	6,421	1,084	782	11,136	7,203
Domestic	8,862	5,309	957	663	9,819	5,972
Foreign	1,190	1,112	127	119	1,317	1,231
Total	10,052	6,421	1,084	782	11,136	7,203

Gross natural gas and crude oil wells include 494 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 Sales Price		
Year Ended December 31,	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Average Lease Operating Cost per Boe	Oil (Per bbl)	NGL (Per bbl)	Gas (Per Mcf)
2021							
United States	27.4	24.2	192.5	$ 8.37	$ 67.37	$ 27.85	$ 3.92
Egypt[(1)]	25.7	0.2	96.2	11.48	70.33	48.84	2.81
North Sea[(2)]	13.2	0.4	14.1	26.12	69.67	54.30	12.96
Total	66.3	24.8	302.8	11.31	68.97	28.48	3.99
2020							
United States	32.3	27.1	205.6	$ 7.39	$ 37.42	$ 11.21	$ 1.22
Egypt[(1)]	27.6	0.3	100.4	10.35	39.95	27.83	2.79
North Sea[(2)]	18.4	0.7	21.0	15.60	42.88	29.73	3.19
Total	78.3	28.1	327.0	9.37	39.60	11.84	1.83
2019							
United States	38.3	25.0	233.5	$ 9.24	$ 54.71	$ 14.95	$ 1.26
Egypt[(1)]	30.9	0.3	104.4	10.77	63.76	33.87	2.83
North Sea[(2)]	18.2	0.6	19.9	16.75	65.10	36.83	4.48
Total	87.4	25.9	357.8	10.62	60.05	15.74	1.90

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

(2) Sales volumes from the Company's North Sea assets for 2021, 2020, and 2019 were 16.1 MMboe, 22.7 MMboe, and 21.8 MMboe, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

Gross and Net Undeveloped and Developed Acreage

The following table summarizes the Company's gross and net acreage position as of December 31, 2021:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(In thousands)			
United States	2,862	1,278	947	568
Egypt	3,610	3,610	1,690	1,634
North Sea	309	290	185	139
Other International	2,934	1,737	—	—
Total	9,715	6,915	2,822	2,341

As of December 31, 2021, the Company held 636,000 net undeveloped acres that are scheduled to expire by year-end 2022 if production is not established or the Company takes no action to extend the terms. The Company also held 10,000 and 97,000 net undeveloped acres set to expire by year-end 2023 and 2024, 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. No oil and gas reserves were recorded on this undeveloped acreage set to expire.

Exploration concessions in the Company's Egypt asset were extended upon ratification of the modernized PSC with the EGPC, and no acreage is scheduled to expire over the next three years. The Company will continue to pursue acreage extensions and access to new concessions in areas in which it believes exploration opportunities exist.

Additionally, the Company has exploration interests in Block 53 and Block 58 offshore Suriname and offshore the Dominican Republic. Approximately 390,000 net undeveloped acres in Block 53 are set to expire in 2022 contingent on planned drilling activity. The Company also continues to assess, contract, and potentially explore undeveloped acreage positions in other international locations.

As of December 31, 2021, approximately 93 percent of U.S. net undeveloped acreage was held by production or owned as undeveloped mineral rights.

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, APA 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. The Company will, at times, utilize additional technical analysis, such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods, to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of the Company's reserve estimates.

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

The following table shows proved oil, NGL, and gas reserves as of December 31, 2021, based on average commodity prices in effect on the first day of each month in 2021, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. The total column of 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	181	164	1,238	551
Egypt[(1)]	107	1	465	185
North Sea	77	2	76	92
Total	365	167	1,779	828
Proved Undeveloped:				
United States	18	16	184	65
Egypt[(1)]	11	—	10	13
North Sea	6	—	7	7
Total	35	16	201	85
Total Proved	400	183	1,980	913

(1) Includes total proved developed and total proved undeveloped reserves of 62 MMboe and 4 MMboe, respectively, attributable to a one-third noncontrolling interest in Egypt.

As of December 31, 2021, the Company had total estimated proved reserves of 400 MMbbls of crude oil, 183 MMbbls of NGLs, and 2.0 Tcf of natural gas. Combined, these total estimated proved reserves are the volume equivalent of 913 million boe, of which liquids represents 64 percent. As of December 31, 2021, the Company's proved developed reserves totaled 828 MMboe and estimated PUD reserves totaled 85 MMboe, or approximately 9 percent of worldwide total proved reserves. APA has elected not to disclose probable or possible reserves in this filing. The Company has one field that contains 15 percent or more of its total proved reserves for the years ended December 31, 2021 and 2020, and none in 2019.

During 2021, the Company added 102 MMboe of proved reserves through exploration and development activity. There were also upward revisions of previously estimated reserves of 107 MMboe. Upward revisions related to changes in product prices accounted for 85 MMboe. Engineering and performance upward revisions accounted for 22 MMboe, with the modernized PSC in Egypt resulting in an increase of 57 MMboe, partially offset by other downward revisions of 35 MMboe across all of the Company's geographic areas of operations. The Company also sold 28 MMboe of proved reserves associated with U.S. divestitures, primarily related to the Permian Basin.

As previously discussed, in December 2021, the Egyptian government signed into law an agreement to modernize and consolidate a majority of the Company's Egypt PSCs. The impact of the consolidated PSC to proved reserves based on the modernized terms is an estimated increase of 53 MMboe and 4 MMboe in developed and undeveloped reserves, respectively, and approximately $750 million in discounted future net cash flows. Approximately 96 percent of the Company's Egypt reserves are now consolidated within the modernized PSC. These estimates include Sinopec's noncontrolling interest in Egypt.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2021, 2020, and 2019, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 18—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on 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 85 MMboe as of December 31, 2021, increased by 9 MMboe from 76 MMboe of PUD reserves reported at year end 2020. During the year, the Company converted 33 MMboe of PUD reserves to proved developed reserves through development drilling activity. In the U.S., the Company converted 28 MMboe, with the remaining 5 MMboe in its international areas. The Company sold 2 MMboe of PUD reserves in the U.S. and did not acquire any PUD reserves during the year. The Company added 63 MMboe of new PUD reserves through extensions and discoveries. Downward revisions totaled 19 MMboe, comprising 7 MMboe associated with engineering and interest revisions, 11 MMboe associated with revised development plans, and 1 MMboe associated with product prices.

During 2021, a total of approximately $213 million was spent on projects associated with proved undeveloped reserves. A portion of APA's costs incurred each year relate to development projects that will convert undeveloped reserves to proved developed reserves in future years. During 2021, the Company spent approximately $174 million on PUD reserve development activity in the U.S. and $39 million in the international areas. As of December 31, 2021, the Company 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

The Company'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.

APA'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 the Company'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 APA's Board of Directors in summary form on a quarterly basis. Annually, each property is reviewed in detail by our corporate and operating asset engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable.

APA's Executive Vice President of Development is the person primarily responsible for overseeing the preparation of the Company's 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 Development reports directly to the Company's 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. The Company engages Ryder Scott Company, L.P. Petroleum Consultants (Ryder Scott) to conduct a reserves audit, which includes a review of the Company's processes and the reasonableness of the Company's 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 2021, the properties selected for each country ranged from 82 to 84 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for 83 percent of the value of the Company's international proved reserves and 94 percent of the value of the Company'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 80 percent of total proved reserves on a boe basis.

Ryder Scott's review for the years 2021, 2020, and 2019 covered 83, 85, and 87 percent, respectively, of the value and 80, 81, and 85 percent, respectively, of the volume of the Company's worldwide estimated proved reserves. Ryder Scott's 2021 review covered 80, 80, and 81 percent of the estimated proved reserve volume in the U.S., Egypt, and U.K., respectively.

Ryder Scott's review of 2020 covered 80 percent of U.S., 82 percent of Egypt, and 83 percent of the U.K.'s total proved reserves.

Ryder Scott's review of 2019 covered 85 percent of U.S., 86 percent of Egypt, and 80 percent of the U.K.'s total proved reserves.

The Company has filed Ryder Scott's independent report as an exhibit to this Annual Report on Form 10-K.

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

ALTUS MIDSTREAM

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

Because a wholly owned subsidiary of APA has a controlling financial interest in Altus, APA fully consolidates the assets and liabilities of Altus in its consolidated financial statements, with a corresponding noncontrolling interest reflected separately.

Business Combination with BCP

On October 21, 2021, ALTM announced that it will combine with privately owned BCP Raptor Holdco LP (BCP and, together with BCP Raptor Holdco GP, LLC, the Contributed Entities) in an all-stock transaction, pursuant to the Contribution Agreement dated as of that same date and entered into by and among ALTM, Altus Midstream LP, New BCP Raptor Holdco, LLC (the Contributor), and BCP (the BCP Contribution Agreement). The combination creates an integrated midstream company in the Texas Delaware Basin offering services for residue gas, NGLs, crude oil and water. There are numerous expected commercial and financial synergies generated from the complementary midstream systems and enhanced scale of the business. The combined business will have a more diversified asset profile and customer base, with a lower risk profile than either entity on a stand-alone basis. BCP is the parent company of EagleClaw Midstream, which includes EagleClaw Midstream Ventures, the Caprock Midstream and Pinnacle Midstream businesses, and a 26.7 percent interest in the Permian Highway Pipeline. Pursuant to the BCP Contribution Agreement, Contributor will contribute all of the equity interests of the Contributed Entities (the Contributed Interests) to Altus Midstream LP, with each Contributed Entity becoming a wholly owned subsidiary of Altus Midstream LP (the BCP Business Combination).

As consideration for the contribution of the Contributed Interests, ALTM will issue 50 million shares of Class C Common Stock (and Altus Midstream LP will issue a corresponding number of common units) to BCP's unitholders, which are principally funds affiliated with Blackstone and I Squared Capital. The transaction is expected to close during the first quarter of 2022 following completion of customary closing conditions.

As a result of the transaction, ALTM's current stockholders will continue to hold their shares of Class A Common Stock and Class C Common Stock (collectively, ALTM Common Stock), Contributor or its designees will collectively own approximately 75 percent of the issued and outstanding shares of ALTM Common Stock, Apache Midstream LLC, a wholly owned subsidiary of APA, which currently owns approximately 79 percent of the issued and outstanding shares of ALTM Common Stock, will own approximately 20 percent of the issued and outstanding shares of ALTM Common Stock, and the remaining current stockholders will own approximately 5 percent of the issued and outstanding shares of ALTM Common Stock.

Gathering, Processing, and Transmission Assets

Altus owns, develops, and operates gas gathering, processing, and transmission assets in the Permian Basin of West Texas. Altus generates revenue by providing fee-based natural gas gathering, compression, processing, and transmission services for the Company's production from its Alpine High resource play. As of December 31, 2021, Altus' assets included approximately 182 miles of in-service natural gas gathering pipelines, approximately 46 miles of residue-gas pipelines with four market connections, and approximately 38 miles of NGL pipelines. Three cryogenic processing trains, each with nameplate capacity of 200 MMcf/d, were placed into service during 2019. Other assets include an NGL truck loading terminal with six Lease Automatic Custody Transfer units and eight NGL bullet tanks with 90,000 gallon capacity per tank. Altus' existing gathering, processing, and transmission infrastructure is expected to provide capacity levels capable of fulfilling its midstream contracts to service the Company's production from Alpine High and third-party customers as market activity in the area continues to develop.

Pipeline Options and Equity Method Interest Pipelines

Gulf Coast Express Pipeline In December 2018, Altus Midstream LP closed on the exercise of its Pipeline Option with Kinder Morgan Texas Pipeline LLC (Kinder Morgan), thereby acquiring a 15 percent equity interest in the Gulf Coast Express Pipeline Project (GCX). Altus Midstream LP acquired an additional 1 percent equity interest in May 2019, for a total 16 percent equity interest in GCX. GCX is a long-haul natural gas pipeline with capacity of approximately 2.0 Bcf/d and transports natural gas from the Waha area in Northern Pecos County, Texas to the Agua Dulce Hub near the Texas Gulf Coast. GCX is operated by Kinder Morgan and was placed into service in September 2019.

EPIC Crude Oil Pipeline In March 2019, Altus Midstream LP's subsidiary closed on the exercise of its Pipeline Option with EPIC Pipeline LP, thereby acquiring a 15 percent equity interest in the EPIC crude oil pipeline (EPIC). The long-haul crude oil pipeline extends from the Orla area in Northern Reeves County, Texas to the Port of Corpus Christi, Texas, and has Permian Basin initial throughput capacity of approximately 600 MBbl/d. The project includes terminals in Orla, Pecos, Crane, Wink, Robstown, Hubson, and Gardendale, Texas with Port of Corpus Christi connectivity and export access. It services Delaware Basin, Midland Basin, and Eagle Ford Shale production. EPIC is operated by EPIC Consolidated Operations, LLC and was placed into service in early 2020.

Permian Highway Pipeline In May 2019, Altus Midstream LP's subsidiary closed on the exercise of its Pipeline Option with Kinder Morgan, thereby acquiring an approximate 26.7 percent equity interest in the Permian Highway Pipeline (PHP). The long-haul natural gas pipeline has capacity of approximately 2.1 Bcf/d and transports 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. PHP, which is operated by Kinder Morgan, was placed into service in January 2021.

Shin Oak NGL Pipeline In July 2019, Altus Midstream LP's subsidiary closed on the exercise of its Pipeline Option with Enterprise Products Operating LLC (Enterprise Products), thereby acquiring a 33 percent equity interest in Breviloba LLC, which owns the Shin Oak NGL Pipeline (Shin Oak). The long-haul NGL pipeline has capacity of up to 550 MBbl/d and transports NGL production from the Orla area in Northern Reeves County, Texas through the Waha area in Northern Pecos County, Texas, and on to Mont Belvieu, Texas. Shin Oak is operated by Enterprise Products and was placed into service during 2019.

MAJOR CUSTOMERS

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. During 2021, sales to EGPC and CFE International accounted for approximately 14 percent and 10 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues. During 2020, sales to EGPC and Vitol accounted for approximately 17 percent and 14 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues. During 2019, sales to BP and Sinopec, and their respective affiliates, each accounted for approximately 10 percent and 11 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues.

Management does not believe that the loss of any one of these customers would have a material adverse effect on the results of operations.

HUMAN CAPITAL MANAGEMENT

Human Capital and Employees

APA believes that its people are one of the Company's most important investments and greatest asset. Successful execution of the Company's business strategies depends on its ability to attract, develop, incentivize, and retain diverse, talented, qualified, and highly skilled employees at all levels of the organization. As such, the Company continues to focus on health and safety, diversity and inclusion, total rewards, and community partnerships to ensure that being a part of the APA family is a positive experience for all.

As of December 31, 2021, the Company employed approximately 2,253 full-time equivalent employees in locations across the organization.

	Employees
North America	1
United Kingdom	
Egypt	
Suriname	
France	
Total employees	2

Women in Global Workforce		Women in Global Leadership Roles		Women on the Board of Directors	
Gender	% of Employees	Gender	% of Employees	Gender	% of Employees
F	23%	F	18%	F	30%
M	77%	M	82%	M	70%

Amongst the Company's U.S. workforce, 34 percent self-report as non-white.

U.S. Employees	
Race	**% of Employees**
American Indian or Alaskan Native	1 %
Asian	7 %
Black or African American	6 %
Hispanic/Latino	19 %
Native Hawaiian or Other Pacific Islander	— %
Two or More Races	1 %
White	66 %

The Company does not request racial diversity data from its non-U.S. colleagues, where tracking these metrics is largely prohibited by law.

COVID-19 Response

Since the onset of the COVID-19 pandemic, the Company has put employee health and well-being front and center, and it has adjusted its approach to how work gets done accordingly. APA's guiding principles for decisions and actions throughout the pandemic have been safety, flexibility, and empathy.

APA implemented and/or supported a tracking and case management system across the Company's operational locations to further protect and support people, while minimizing the impact to the business. In the U.S., for example, the Company managed nearly 800 cases of potential or confirmed exposure and illness (through mid-2021), providing individual support. The Company also coordinated efforts with a third-party medical provider to offer vaccinations and boosters to employees and their dependents on a voluntary basis. Each operating area, in the U.S., U.K., Egypt, and Suriname, used specific tracking systems, which were ultimately managed by the U.S. case management team. This oversight process provided for comprehensive reporting and analysis to key leadership to enable effective decision-making.

Oversight and Management

The Company's Board of Directors has three standing committees, each devoted to a separate aspect of risk oversight. The Management Development and Compensation (MD&C) Committee, the Audit Committee, the Corporate Responsibility, Governance, and Nominating (CRG&N) Committee, and/or the full Board of Directors receive regular reports on certain human capital matters, including the Company's diversity and inclusion programs and initiatives.

- The MD&C Committee oversees the Company's compensation programs, leadership development and succession planning strategies, and seeks continuous improvement in the diversity and inclusion practices used in developing and deploying these processes.
- The Audit Committee oversees the integrity of the Company's financial statements and monitors human capital management risk against compliance with legal and regulatory requirements.
- The CRG&N Committee oversees the nomination of Company directors, the annual Board of Directors evaluation process, corporate governance and ESG issues, as well as the Company's annual sustainability report.

Reports and recommendations made to the Board of Directors and its committees are part of the framework that ensures APA's daily actions and decisions are guided by its core values, including upholding the health and safety of the Company's team, stakeholders, and communities; investing in its workforce; ensuring environmental responsibility; and acting ethically and with integrity.

Diversity and Inclusion

APA recognizes diversity and inclusion (D&I) as vital to its long-term success. In 2020, the Company established a dedicated D&I function to build on its commitment to D&I across the organization. Since that time, APA's focus has been on providing unconscious bias training for its global workforce, expanding employee resource groups (ERGs) in terms of quantity and geography, and increasing awareness about the importance of D&I and each employee's role in ensuring that APA has a culture where all employees are valued and can thrive with a sense of belonging, not just as employees, but as people.

In 2021, APA strengthened its commitment through the following key accomplishments:

- Launching annual mandatory D&I training for all of the Company's people leaders, and assigning it as recommended training for all employees across our global locations;
- Refreshing the Global D&I Council to obtain employee perspectives and feedback on the Company's D&I initiatives;
- Increasing employee engagement by promoting the establishment of Employee Resource Groups;
- Launching global employee engagement campaigns to celebrate the diversity of the Company's employees;
- Introducing a global mentorship program to promote access to leadership and career development;
- Conducting annual pay equity analysis; and
- Expanding community outreach efforts to continue APA's support of underserved populations

Talent

Throughout the Company, APA seeks to attract, develop, and retain the best talent. During 2021, the Company expanded its talent management organization with dedicated talent acquisition and development functions that have both established and implemented hiring and development processes, including standardizing candidate selection. APA honed its global succession planning program by including a robust assessment of competency proficiency levels for identified successors. The Company continues to advance its global employee development strategy through formal development plans, on-the-job learning, and challenging work assignments that strengthen business critical skillsets to meet future workforce needs. APA also deployed a leadership development program that embeds a leadership framework detailing clear behaviors that the Company expects from its people leaders to ensure they align with its culture.

Training and Development

During 2021, the Company launched an updated approach to global performance management focusing on development, which included a detailed framework for core, leadership, and technical competencies. This approach emphasizes ongoing performance conversations between managers and employees with a focus on mitigating bias in performance conversations.

In addition, employees create a personal development plan, and APA provides additional resources to support employees in their personal and professional development, including:

- Utilization of multiple, third-party online training offerings;
- Leadership and personal development coaching opportunities through a collaboration with a leading human resources consulting company;
- Ongoing education for people leaders around the Company's leadership competencies and behaviors;
- Annual compliance, antitrust, bribery, corruption, and code of business conduct and ethics training required for all employees and leaders; and
- Cybersecurity training focusing on keeping the Company and employees' personal information secure.

Total Rewards

Year after year, APA has steadily upgraded its total rewards compensation programs with the objective of retaining, rewarding, and attracting the best talent by providing total rewards that are competitive. To foster a stronger sense of ownership and align the interests of employees and shareholders, restricted stock units are provided to eligible employees under APA's broad-based compensation program. Furthermore, the Company offers comprehensive, locally relevant and innovative benefits. In the U.S. these include, among other benefits:

- Comprehensive health insurance coverage offered to employees working an average of 20 hours or more each week;
- 401(k) plan with up to 8 percent Company match;
- 6 percent Company contributions to a money purchase retirement plan;
- Company-paid short-term disability that pays a percentage of base pay according to years of service;
- Parental leave for all new parents for birth and adoption;
- Elder care leave to temporarily care for or find permanent care for elder family members; and

- Mental health and well-being benefits, including free coaching and therapy as well as access to self-care resources and a well-being platform that offers ongoing training and challenges to help employees with sustaining healthy habits.

Health and Safety

APA's priority is the health and safety of its workforce. The Company's environmental, health, and safety and operations functions partner to consistently reinforce its core values, standards, and operating practices, as well as foster a safety culture that empowers the Company's workforce to stop work if conditions or behaviors are deemed unsafe. APA strives to be incident-free across its global operations every day, with the help of visible and engaged leadership, by setting clear expectations and making safety personal for all employees and contractors.

2021 Global Primary Workforce Safety Goals

Total Recordable Incident Rate (TRIR)	0.26	44% below target of 0.46
Days Away, Restricted and Transferred Rate (DART)	0.13	40% below target of 0.22
Severe Injury and Fatality Rate (SIF)	0.016	59% below target of 0.039
Vehicle Incident Rate (VIR)	0.53	39% below target of 0.87

Community Partnerships

APA is committed to being socially and environmentally responsible in the communities where it operates. The Community Partnerships group oversees the Company's global strategic social investing and community engagement, including the stewardship of key stakeholder relationships.

APA's global giving strategy and philosophy is focused into three pillars: Sustainable Communities, Environmental Stewardship, and Access to Energy, through which the Company creates sustainable and positive impacts. Based on these pillars, APA is committed to addressing acute social needs within the local communities where it operates; ensuring that it remains focused on its long-standing legacy and commitment to environmental stewardship and conservation; and supporting underserved communities that lack access to reliable, affordable energy.

- Sustainable Communities: APA continues to partner with organizations within the communities in which it operates to improve quality of life through access to education and essential medical supplies; development of innovative healthcare technologies and procedures; support for vulnerable populations, including women and children in need; response to natural disasters; and support for first responders.
- Environmental Stewardship: In 2021, the Company's environmental stewardship initiatives included grants of 55,000 trees to 66 community partners through the APA Corporation Tree Grant Program; continued partnership with the Texas Parks and Wildlife Foundation to provide sustainable funding for the restoration of Balmorhea State Park; and multi-year support of the Pecos Watershed Conservation Initiative, an alliance of seven energy companies, in partnership with the National Fish and Wildlife Foundation, to restore and protect natural grasslands and habitats within the greater Trans-Pecos Region.
- Access to Energy: The Company continues to partner with Switch Energy Alliance, which provides collaborative global energy education and solutions for more than 15 million students and environmental organizations.

APA also provides employees with volunteer service opportunities in collaboration with our Community Partnerships program. The Company seeks meaningful volunteer opportunities that instill a sense of pride, ownership, and accomplishment for employees in their communities. As community needs change and stakeholder engagement continues, APA continues to adjust its charitable giving program.

OFFICES

The Company's principal executive offices are located at One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400. As of year-end 2021, the Company maintained offices in Midland, Texas; Houston, Texas; Cairo, Egypt; and Aberdeen, Scotland. The Company leases its primary office space. The current lease on the Company's 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 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

TITLE TO INTERESTS

As is customary in the oil and gas industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time the Company acquires properties. The Company believes that its 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 the Company's operations. The interests owned by the Company 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 the Company's operations.

ADDITIONAL INFORMATION ABOUT THE COMPANY

Response Plans and Available Resources

The Company's subsidiaries developed Oil Spill Response Plans (the Plans) for their respective offshore operations in the Gulf of Mexico, the North Sea, and Suriname, which 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.

The Company's subsidiary, Apache, is a member of Oil Spill Response Limited (OSRL), a large international oil spill response cooperative, which entitles any affiliated entity worldwide to access OSRL's services. Apache also has a contract for 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. Apache is a member 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.

Additionally, the Company is an active member of Wild Well Control's WellCONTAINED Subsea Containment System for Suriname operations. This membership includes contingency planning, and response, to an uncontrolled subsea well event. The Company utilizes a detailed Source Control Emergency Response Plan (SCERP) for offshore Suriname planning. The SCERP has been designed to ensure that the goals of the Company's source control emergency preparedness efforts will be met in the unlikely event of an actual response to an uncontrolled well event. This includes the use of subsea dispersant systems and field deployment of one of Wild Well Control's containment system capping stacks.

Competitive Conditions

The oil and gas industry 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 NGLs. The Company's 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 the Company’s competitors may possess financial or other resources substantially larger than the Company possesses or have established strategic long-term positions and maintain strong governmental relationships in countries in which the Company may seek new entry. As a consequence, the Company may be at a competitive disadvantage in bidding for leases or drilling rights.

However, the Company believes its diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across three geographic areas, its balanced production mix between oil and gas, its management and incentive systems, and its experienced personnel give it a strong competitive position relative to many of the Company’s competitors who do not possess similar geographic and production diversity. The Company’s global position provides a large inventory of geologic and geographic opportunities in the geographic areas in which it has producing operations to which it can reallocate capital investments in response to changes in commodity prices, local business environments, and markets. This also reduces the risk that the Company 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, the Company is subject to numerous federal, state, local, and foreign 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, the Company does not believe that these requirements affect it differently, to any material degree, than other companies in the oil and gas industry.

The Company has made and will continue to make expenditures in its efforts to comply with these requirements, which the Company believes are necessary business costs in the oil and gas industry. The Company has established policies for continuing compliance with environmental laws and regulations, including regulations applicable to its operations in all countries in which it does business. The Company has established operating procedures and training programs designed to limit the environmental impact of its 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 the Company is unable to separate expenses related to environmental matters; however, the Company does not believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on its capital expenditures, earnings, or competitive position.

ITEM 1A. *RISK FACTORS*

The Company's business activities and the value of its securities are subject to significant hazards and risks, including those described below. If any of such events should occur, the Company's business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of APA's securities could lose part or all of their investments. Additional risks relating to the Company's securities may be included in the prospectus supplements related to offerings of such securities from time to time in the future.

RISKS RELATED TO PRICING, DEMAND, AND PRODUCTION FOR CRUDE OIL, NATURAL GAS, AND NGLs

The COVID-19 pandemic has and may continue to adversely impact the Company's business, financial condition, and results of operations, the global economy, and the demand for and prices of oil, natural gas, and NGLs. The unprecedented nature of the current situation makes it impossible for the Company to identify all potential risks related to the pandemic or estimate the ultimate adverse impact that the pandemic may have on its business.

The COVID-19 pandemic and the actions taken by third parties, including, but not limited to, governmental authorities, businesses, and consumers, in response to the pandemic have adversely impacted the global economy and created significant volatility in the global financial markets. Business closures, restrictions on travel, "stay-at-home" or "shelter-in-place" orders, and other restrictions on movement within and among communities have significantly reduced demand for and the prices of oil, natural gas, and NGLs. As of the date of this Annual Report on Form 10-K, efforts to contain COVID-19 have not been successful in many regions, vaccination distribution programs have encountered delays, new variants have emerged, and the global pandemic remains ongoing. While some geographic regions have lifted, relaxed, or otherwise modified their pandemic response measures to lessen the impact of such measures on business operations and commerce, these regions may reinstitute restrictions as circumstances change. A continued, prolonged period or a renewed period of reduced demand, the failure to timely distribute or the ineffectiveness of or reluctance or refusal of individuals to take any vaccines, the failure to develop adequate treatments, and other adverse impacts from the pandemic may materially adversely affect the Company's business, financial condition, cash flows, and results of operations.

The Company's operations rely on its workforce being able to access its wells, platforms, structures, and facilities located upon or used in connection with its oil and gas leases. Additionally, because the Company has previously implemented, and may elect to or be required in the future to reimplement, remote working procedures for a significant portion of its workforce for health and safety reasons and/or to comply with applicable national, state, and/or local government requirements, the Company relies on such persons having sufficient access to its information technology systems, including through telecommunication hardware, software, and networks. If a significant portion of the Company's workforce cannot effectively perform their responsibilities, whether resulting from a lack of physical or virtual access, quarantines, illnesses, governmental actions or restrictions, including vaccine mandates and the reactions thereto, information technology or telecommunication failures, or other restrictions or adverse impacts resulting from the pandemic, the Company's business, financial condition, cash flows, and results of operations may be materially adversely affected.

The unprecedented nature of the current situation resulting from the COVID-19 pandemic makes it impossible for the Company to identify all potential risks related to the pandemic or estimate the ultimate adverse impact that the pandemic may have on its business, financial condition, cash flows, or results of operations. Such results will depend on future events, which the Company cannot predict, including the scope, duration, and potential reoccurrence of the COVID-19 pandemic, the emergence and impact of COVID-19 variants, or any other localized epidemic or global pandemic, the distribution and effectiveness of vaccines, therapeutics, and treatments, the demand for and the prices of oil, natural gas, and NGLs, and the actions taken by third parties, including, but not limited to, governmental authorities, customers, contractors, and suppliers, in response to the COVID-19 pandemic or any other epidemics or pandemics. The COVID-19 pandemic and its unprecedented consequences have amplified, and may continue to amplify, the other risks identified in this Annual Report on Form 10-K.

Crude oil, natural gas, and NGL price volatility could adversely affect the Company's operating results and the price of APA's common stock.

The Company's revenues, operating results, and future rate of growth depend highly upon the prices it receives for its 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 2021 ranged from a high of $85.64 per barrel to a low of $47.47 per barrel. The NYMEX daily settlement price for the prompt month natural gas contract in 2021 ranged from a high of $23.86 per MMBtu to a low of $2.43 per MMBtu. The market prices for crude oil, natural gas, and NGLs depend on factors beyond the Company’s 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 occurrence of global events such as epidemics or pandemics (including, specifically, the COVID-19 pandemic) and the actions taken by third parties, including, but not limited to, governmental authorities, customers, contractors, and suppliers, in response to such epidemics or pandemics;
- 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;
- the impact of political pressure and the influence of environmental groups and other stakeholders on decisions and policies related to the industries in which the Company and its affiliates operate;
- domestic and foreign governmental regulations and taxes, including legislative, regulatory, policy changes, or initiatives and addressing the impact of global climate change, hydraulic fracturing, methane emissions, flaring, or water disposal; and
- the overall economic environment.

The Company’s results of operations, as well as the carrying value of its oil and gas properties, are substantially dependent upon the prices of oil, natural gas, and NGLs. Low prices have previously adversely affected and could again adversely affect the Company’s revenues, operating income, cash flow, and proved reserves, and continued low prices could have a material adverse impact on the Company’s operations and limit its ability to fund capital expenditures. Without the ability to fund capital expenditures, the Company would be unable to replace reserves and production. Sustained low prices of crude oil, natural gas, and NGLs may further adversely impact the Company’s business as follows:

- weakening the Company’s financial condition and reducing its liquidity;
- limiting the Company’s ability to fund planned capital expenditures and operations;
- reducing the amount of crude oil, natural gas, and NGLs that the Company can produce economically;
- causing the Company to delay or postpone some of its capital projects;
- reducing the Company’s revenues, operating income, and cash flows;
- limiting the Company’s access to sources of capital, such as equity and long-term debt;
- reducing the carrying value of the Company’s oil and gas properties, resulting in additional non-cash impairments; or
- reducing the carrying value of the Company’s gathering, processing, and transmission facilities, resulting in additional impairments.

The Company’s ability to sell crude oil, natural gas, or NGLs and/or receive market prices for these commodities and/or meet volume commitments under transportation services agreements may be adversely affected by pipeline and gathering system capacity constraints, the inability to procure and resell volumes economically, and various transportation interruptions.

A portion of the Company’s 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 the Company’s production, or the Company might voluntarily curtail production in response to market conditions. If a substantial amount of the Company’s production is interrupted at the same time, it could temporarily adversely affect the Company’s cash flows. Additionally, if the Company is unable to procure and resell third-party volumes at or above a net price that covers the cost of transportation, the Company’s cash flows could be adversely affected.

The Company may not realize an adequate return on wells that it drills.

Drilling for oil and gas involves numerous risks, including the risk that the Company will not encounter commercially productive oil or gas reservoirs. The wells the Company drills or participates in may not be productive, and the Company may not recover all or any portion of its investment in those wells. The seismic data and other technologies the Company uses do not allow it 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, such failure could have an adverse effect on the Company’s future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.

The Company’s commodity price risk management and trading activities may prevent it from benefiting fully from price increases and may expose it to other risks.

To the extent that the Company engages in price risk management activities to protect itself from commodity price declines, the Company may be prevented from realizing the benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company’s hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

RISKS RELATED TO OPERATIONS AND DEVELOPMENT PROJECTS

The Company’s operations involve a high degree of operational risk, particularly risk of personal injury, damage to or loss of equipment, and environmental accidents.

The Company’s 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, fires, and cratering;
- pipeline or other facility ruptures and spills;
- formations with abnormal pressures;

- equipment malfunctions;
- hurricanes, major storms, and cyclones, which could affect the Company's operations in areas such as on and offshore the Gulf Coast, North Sea, and Suriname, 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 the Company could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, fire at a location where the Company's equipment and services are used, or ground water contamination from chemical additives used in hydraulic fracturing 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 could result in extensive environmental pollution and substantial remediation expenses. If a significant amount of the Company's production is interrupted, containment efforts prove to be ineffective, or litigation arises as the result of a catastrophic occurrence, the Company's cash flows and, in turn, its results of operations could be materially and adversely affected.

Weather and climate may have a significant adverse impact on the Company's revenues and production.

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impact the price the Company receives for the commodities it produces. In addition, the Company's exploration, development, and production activities and equipment have been and can be adversely affected by severe weather, such as freezing temperatures, hurricanes in the Gulf of Mexico, or major storms in the North Sea, which have previously caused and may cause a loss of production from temporary cessation of activity or lost or damaged equipment. The Company's 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.

The Company's insurance policies do not cover all of the risks the Company faces, 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. The Company's international operations are also subject to political risk. The insurance coverage that the Company maintains against certain losses or liabilities arising from its operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to the Company against all operational risks.

A terrorist or cyberattack targeting systems and infrastructure used by the Company or others in the oil and gas industry may adversely impact the Company's operations.

The Company's business has become increasingly dependent on digital technologies to conduct certain exploration, development, and production activities. The Company depends 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 personnel and third-party partners, and conduct many of the Company's activities. Unauthorized access to the Company's 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. Also, external digital technologies control nearly all of the oil and gas distribution and refining systems in the U.S. and abroad, which are necessary to transport and market the Company's production. A cyberattack directed at oil and gas distribution systems have previously and 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 its customers, suppliers, or others with whom it does business could have a material adverse effect on the Company's business, cause it to incur a material financial loss, subject it to possible legal claims and liability, and/or damage its reputation.

While certain of the Company's insurance policies may allow for coverage of associated damages resulting from such events, if the Company were to incur a significant liability for which it was not fully insured, that could have a material adverse effect on the Company's financial position, results of operations, and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

While the Company has experienced cyberattacks in the past, it has not suffered any material losses as a result of such attacks; however, there is no assurance that the Company will not suffer such losses in the future. Further, as cyberattacks continue to evolve, the Company may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any vulnerabilities to cyberattacks. In addition, cyberattacks against the Company or others in its 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 that such additional regulations could have on its business and operations or the energy industry at large.

Material differences between the estimated and actual timing of critical events or costs may affect the completion and commencement of production from development projects.

The Company is involved in several large development projects, and the completion of these projects may be delayed beyond the Company's anticipated completion dates. These 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 the Company's large development projects and its ability to participate in large-scale development projects in the future. In addition, the Company's estimates of future development costs are based on its current expectations of prices and other costs of equipment and personnel the Company will need to implement such projects. The actual future development costs may be significantly higher than the Company currently estimates. If costs become too high, the development projects may become uneconomic to the Company, and it may be forced to abandon such development projects.

RISKS RELATED TO RESERVES AND LEASEHOLD ACREAGE

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.

The production rate from oil and natural 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 the Company adds reserves through exploration and development activities, identifies additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves through engineering studies, or acquires additional properties containing proved reserves, the Company's estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon the Company's level of success in acquiring or finding additional reserves on an economic basis. Furthermore, as oil or natural gas prices increase, the Company's cost for additional reserves could also increase.

The Company may fail to fully identify potential problems related to acquired reserves or to properly estimate those reserves.

Although the Company performs a review of properties that it acquires, which the Company believes 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, the Company will focus its 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 the Company 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, the Company often assumes 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 the Company's operating results, particularly during the periods in which the operations of acquired businesses are being integrated into the Company's ongoing operations.

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. The Company's 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 the Company's 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 the Company's reserves likely will vary, possibly materially, from estimates.

Additionally, because some of the Company's 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 the Company's 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 the Company's 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 the Company's 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 the leases expire, the Company will lose its right to develop the related properties. The Company's 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.

RISKS RELATED TO COUNTERPARTIES

The credit risk of financial institutions could adversely affect the Company.

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

The Company is 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 changes 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. The Company is unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if the Company does accurately predict sudden changes, its ability to negate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of the Company's hedge providers or some other similar proceeding or liquidity constraint might make it unlikely that the Company would be able to collect all or a significant portion of amounts owed to it by the distressed entity or entities. During periods of falling commodity prices, the Company's hedge receivable positions increase, which increases the Company's exposure. If the creditworthiness of the counterparties deteriorates and results in their nonperformance, the Company could incur a significant loss.

The distressed financial conditions of the Company's purchasers and partners have had and could have an adverse impact on the Company in the event they are unable to pay the Company for the products or services it provides or to reimburse it 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. The Company is exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. The Company sells its crude oil, natural gas, and NGLs to a variety of purchasers. As operator, the Company pays expenses and bills its non-operating partners for their respective shares of costs. As a result of recent economic conditions and the previously severe decline in commodity prices, some of the Company's customers and non-operating partners experienced severe financial problems that had a significant impact on their creditworthiness. The Company cannot provide assurance that one or more of its financially distressed customers or non-operating partners will not default on their obligations to the Company or that such a default or defaults will not have a material adverse effect on the Company's business, financial position, future results of operations, or future cash flows. Furthermore, the bankruptcy of one or more of the Company's customers or non-operating partners or some other similar proceeding or liquidity constraint have made it and might make it unlikely that the Company will or 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.

The Company's liabilities could be adversely affected in the event one or more of its transaction counterparties become the subject of a bankruptcy case.

From time to time the Company has 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, bonds, letters of credit, and similar arrangements. One of the most significant of these liabilities involves the decommissioning of wells and facilities previously owned by the Company. 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 becomes 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 are collectively referred to as Insolvency Laws), the counterparty may not perform its obligations under the agreements related to these transactions. In that case, the Company's 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 the Company has collateral from the counterparty for the performance of the obligations. Resolution of the Company's claim for damages in such a proceeding may be delayed, and the Company may be forced to use available cash to cover the costs of the obligations assumed by the counterparties under such agreements should they arise, pending final resolution of the proceeding.

Despite the provisions in the Company's agreements requiring purchasers of its 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, the Company would expect the relevant governmental authorities to require it to perform and hold it responsible for such liabilities and obligations. In such event, the Company 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 the Company's cash flows, operations, or financial condition.

For additional information regarding Apache's prior Gulf of Mexico properties and the bankruptcy of the purchaser of those properties, see the information set forth under "Potential Obligation to Decommission Sold Properties" in Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Item 15 of this Annual Report on Form 10-K.

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

The Company conducts many of its exploration and production (E&P) operations through joint operating agreements with other parties under which the Company may not control decisions, either because it does not have a controlling interest or is 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 the Company's, and therefore, decisions may be made that the Company does not believe are in its best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations, and the Company may be required to fulfill those obligations alone. In either case, the value of the investment may be adversely affected.

The Company own an approximate 79 percent interest in Altus, which holds substantially all of Apache's former gathering, processing, and transmission assets in Alpine High. Altus may be subject to different risks than those described in this Annual Report on Form 10-K.

The Company owns an approximate 79 percent interest in Altus, which holds substantially all of Apache's 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 the Company's production from Apache's Alpine High resource play. Altus generates revenue by providing fee-based natural gas gathering, compression, processing, and transmission services and through its Equity Method Interest Pipelines. Given the nature of its business, Altus may be subject to different and additional risks than those described in this Annual Report on Form 10-K. For a description of these risks, refer to Altus' most recently filed Annual Report on Form 10-K and any subsequently filed Quarterly Reports on Form 10-Q.

On October 21, 2021, ALTM announced that it will combine with privately owned BCP in an all-stock transaction. The transaction is expected to close during the first quarter of 2022, following completion of customary closing conditions. Upon closing of the transaction, the Company will no longer control Altus.

RISKS RELATED TO CAPITAL MARKETS

A downgrade in the Company's credit rating could negatively impact its cost of and ability to access capital.

The Company receives debt ratings from the major credit rating agencies in the U.S. Factors that may impact the Company's credit ratings include its 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 the Company's ability to access debt markets in the future and increase the cost of future debt. During 2021, the Company's credit rating was affirmed by Moody's to Ba1/Stable and by Standard and Poor's to BB+/Stable. Past ratings downgrades have required, and any future downgrades may require, the Company to post letters of credit or other forms of collateral for certain obligations.

Market conditions may restrict the Company's ability to obtain funds for future development and working capital needs, which may limit its financial flexibility.

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

The Company's syndicated credit facility currently matures in March 2024. There is no assurance of the terms upon which potential lenders under future agreements will make loans or other extensions of credit available to the Company or its subsidiaries or the composition of such lenders.

The discontinuation and uncertain cessation date of LIBOR, and the adoption of an alternative reference rate, may have a material adverse impact on the Company's floating rate indebtedness and financing costs.

Pursuant to the terms of the Company's revolving credit facility (1) the Company may elect to use the London Interbank Offering Rate (LIBOR) as a benchmark for establishing the interest rate on floating interest rate borrowings and (2) the commission payable to the lenders on the face amount of each outstanding letter of credit uses LIBOR as a benchmark. On November 30, 2020, the ICE Benchmark Administration (IBA) announced that it intends to continue publishing LIBOR until the end of June 2023, beyond the previously announced 2021 cessation date. The IBA announcement was supported by announcements from the U.K.'s Financial Conduct Authority (FCA), which regulates LIBOR, and the Board of Governors of the Federal Reserve System, Federal Deposit Insurance Corporation and Office of the Comptroller of the Currency (U.S. Regulators). However, both the FCA and U.S. Regulators in their announcements also advised banks to cease entering into new contracts referencing LIBOR after December 2021. These announcements indicate that the continuation of LIBOR in existing contracts may not be assured after 2021 and will not be assured beyond 2023. In light of these recent announcements, the future of LIBOR at this time is uncertain, and any changes in the methods by which LIBOR is determined or regulatory activity related to LIBOR's phaseout could cause LIBOR to perform differently than in the past or cease to exist.

In the U.S., the Alternative Reference Rates Committee (the working group formed to recommend an alternative rate to LIBOR) has identified the Secured Overnight Financing Rate (SOFR) as its preferred alternative rate for LIBOR. There can be no guarantee that SOFR will become a widely-accepted benchmark in place of LIBOR. Although the full impact of the transition away from LIBOR, including the discontinuance of LIBOR publication and the adoption of SOFR as the replacement rate for LIBOR, remains unclear, these changes may have an adverse impact on the Company's floating rate indebtedness and financing costs under its revolving credit facility.

The Company's ability to declare and pay dividends is subject to limitations.

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

Any indentures and other financing agreements that the Company enters into in the future may limit its ability to pay cash dividends on its capital stock, including APA 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 the Company's total assets exceeds the sum of its total liabilities, including contingent liabilities, and the amount of its capital; if there is no surplus, cash dividends on capital stock may only be paid from the Company's net profits for the then-current and/or the preceding fiscal year. Further, even if the Company is permitted under its contractual obligations and Delaware law to pay cash dividends on common stock, the Company may not have sufficient cash to pay dividends in cash on its common stock.

Unfavorable ESG ratings and funding limitation initiatives may lead to negative investor and public sentiment toward the Company and to the diversion of capital from the Company's industry.

Organizations that provide information to investors on corporate governance and related matters have developed ratings for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform and advise their investment and voting decisions. In addition, certain organizations and stakeholders may encourage lenders to limit funding to E&P companies. Unfavorable ESG ratings and funding limitation initiatives may lead to negative investor and public sentiment toward the Company and to the diversion of capital from the Company's industry, which could have a negative impact on the Company's access to and costs of capital.

RISKS RELATED TO FINANCIAL RESULTS

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

Current global market conditions and uncertainty, including economic instability in emerging markets, are likely to have significant long-term effects on the Company's 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 the Company's oil and natural gas production as well as lower commodity prices, which would reduce the Company's cash flows from operations and its profitability.

The Company faces strong industry competition that may have a significant negative impact on the Company's results of operations.

Strong competition exists in all sectors of the oil and gas E&P industry. The Company competes 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 the Company's competitors have financial and other resources substantially larger than the Company possesses and have established strategic, long-term positions and maintain strong governmental relationships in countries in which the Company may seek new entry. As a consequence, the Company may be at a competitive disadvantage in bidding for drilling rights. In addition, many of the Company's 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. The Company also competes in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. These competitive pressures may have a significant negative impact on the Company's results of operations.

The Company's ability to utilize net operating losses and other tax attributes to reduce future taxable income may be limited if the Company experiences an ownership change.

As described in Note 10—Income Taxes of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K, the Company has substantial net operating loss carryforwards (NOLs) and other tax attributes available to potentially offset future taxable income. If the Company were to experience an "ownership change" under Section 382 of the Internal Revenue Code of 1986, as amended, which is generally defined as a greater than 50 percentage point change, by value, in the Company's equity ownership by five-percent shareholders over a three-year period, the Company's ability to utilize its pre-change NOLs and other pre-change tax attributes to potentially offset its post-change income or taxes may be limited. Such a limitation could materially adversely affect the Company's operating results or cash flows by effectively increasing its future tax obligations.

RISKS RELATED TO GOVERNMENTAL REGULATION AND POLITICAL RISKS

The Company may incur significant costs related to environmental matters.

As an owner or lessee and operator of oil and gas properties, the Company is subject to various federal, state, local, and foreign 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. The Company's efforts to limit its exposure to such liability and cost may prove inadequate and result in significant adverse effects to the Company's results of operations. In addition, it is possible that the increasingly strict requirements imposed by environmental laws and enforcement policies could require the Company to make significant capital expenditures. Such capital expenditures could adversely impact the Company's cash flows and its financial condition.

The Company's U.S. operations are subject to governmental risks.

The Company's U.S. 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 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 the NTL was paused in mid-2017 and is currently listed on BOEM's website as "rescinded," if reinstated, 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. The Company is working closely with BOEM to make arrangements for the provision of such additional required security, if such security becomes necessary under the NTL. Additionally, the Company is 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 the Company's U.S. operations, and increased liability for companies operating in this sector may adversely impact the Company's results of operations.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase the Company's 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. The Company routinely uses 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 the Company conducts business could result in increased compliance costs or additional operating restrictions in the U.S.

Changes in tax rules and regulations, or interpretations thereof, may adversely affect the Company's business, financial condition, and results of operations.

The 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. 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 E&P 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. The Company is unable to predict whether any of these changes or other proposals will be enacted. Any such changes could adversely affect the Company's business, financial condition, and results of operations.

RISKS RELATED TO CLIMATE CHANGE

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

Certain countries where the Company operates, including the U.K., either tax or assess some form of greenhouse gas (GHG) related fees on the Company's operations. Exposure has not been material to date, although a change in existing regulations could adversely affect the Company's cash flows and results of operations. Additionally, there has been discussion in other countries where the Company operates, including the U.S., regarding legislation or regulation of GHG. Numerous proposals have been made and could continue to be made at the national, regional, and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. Moreover, on January 27, 2021, the President issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across governmental agencies and economic sectors.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations, or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, restriction of emissions, electric vehicle mandates, and combustion engine phaseouts. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas, and NGLs. Additionally, political, litigation, and financial risks related to climate change may result in curtailed refinery activity, increased regulation, or other adverse direct and indirect effects on the Company's business, financial condition, and results of operations. For example, there is a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

Any such legislation, regulations, or other regulatory initiatives, if enacted, or additional or increased taxes, assessments, or GHG-related fees on the Company's operations could lead to increased operating expenses or cause the Company to make significant capital investments for infrastructure modifications.

Enhanced scrutiny on ESG matters could have an adverse effect on the Company's operations.

Enhanced scrutiny on ESG matters related to, among other things, concerns raised by advocacy groups about climate change, hydraulic fracturing, waste disposal, oil spills, and explosions of natural gas transmission pipelines 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, increased risk of litigation, and adverse impacts on the Company's access to capital. 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 the Company requires to conduct its operations to be withheld, delayed, or burdened by requirements that restrict the Company's ability to profitably conduct its business.

The Company's estimates used in various scenario planning analyses could differ materially from actual results and could expose us to new or additional risks.

In 2021, the Company undertook a scenario planning analysis in alignment with recommendations of the Financial Stability Board's Taskforce on Climate-related Financial Disclosures ("TCFD"). This expanded climate-focused scenario planning framework included forecasts of future demand and pricing in energy markets, as well as changes in government regulations and policy. Given the dynamic nature of the Company's business, the Company generally performs annual scenario analyses with five-year time horizons. When analyzing longer-term TCFD scenarios, the Company relies on external analysis for demand scenarios, carbon pricing, and comparison-pricing scenarios, which are then compared to the Company's internally prepared base-case pricing analysis averaged out to 2040. Given the numerous estimates that are required to run these scenarios, the Company's estimates could differ materially from actual results. Additionally, by electing to set and share publicly these metrics in the Company's sustainability report and the Company's commitment to expand upon its disclosures, the Company's business may also face increased scrutiny related to ESG initiatives. As a result, the Company could damage its reputation if it fails to act responsibly in the areas in which it reports. Any harm to the Company's reputation resulting from setting these metrics, expanding its disclosures, or its failure or perceived failure to meet such metrics or disclosures could adversely affect the Company's business, financial performance, and growth.

The Company operates in Gulf Coast wetlands, which face threats from climate change and human activities.

A changing climate creates uncertainty and could result in broad changes, both physical and financial, to the areas in which the Company operates, including Gulf Coast wetlands. For several decades, the State of Louisiana has lost an estimated 20 square miles of wetlands per year, due to natural processes of subsidence, saltwater intrusion, and shoreline erosion, as well as human activities, such as levee construction along the Mississippi River and the dredging of navigation canals. A possible result of climate change is more frequent and more severe weather events, such as hurricanes and major flooding events. The risk of increased or more severe hurricanes or flooding events along or near the Gulf Coast could increase the Company's costs to repair damaged facilities and restore production. Additionally, federal, state, and local laws and regulations may impose numerous obligations applicable to the Company's operations including: (i) the limitation or prohibition of certain activities on wetlands; (ii) the imposition of substantial liabilities for pollution resulting from operations; (iii) the reporting of the types and quantities of various substances that are generated, stored, processed, or released in connection with protected properties; and (iv) the installation of costly emission monitoring and/or pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of the Company's operations. In addition, the Company may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt the Company's operations or specific projects and limit its growth and revenue.

The guidance upon which the Company's consumptive water use reporting was modified and could be revised in the future, resulting in the over or underreporting of the Company's consumptive water use, and could expose the Company to financial risk.

Based on Ipieca's Sustainability Reporting Guidance of the Oil and Gas Industry (2020), the Company modified the way it reports its water data compared to previous years and also restated data from past years. Previously, the Company included produced water usage in its consumptive use calculations, which led to an over-reporting of consumptive water use. Based on re-evaluation of water reporting definitions and guidance, the Company determined that produced water – non-potable water released from deep underground formations and brought to the surface during oil and gas exploration and production – should not be classified as consumed in the same sense as fresh water. Produced water is generally not of the quality that most users would be able to utilize and is therefore not available for third-party usage outside of the oilfield. The Company’s revised reporting now reflects only fresh water and non-potable water from surface water or shallow groundwater that are consumed in oil and gas operations.

The treatment and disposal of produced water is becoming more highly regulated and restricted and could expose the Company to additional costs or limit certain operations.

The treatment and disposal of produced water is becoming more highly regulated and restricted. The Company’s ability to accurately report and track its water use is necessary for its continued ability to reuse and recycle water, when possible. While the Company remains focused on reusing or recycling water over disposal of water, the Company’s costs for obtaining and disposing of water could increase significantly if reusing and recycling water becomes impractical. Further, compliance with reporting and environmental regulations governing the withdrawal, storage, use, and discharge of water may increase the Company’s operating costs, which could materially and adversely affect its business, results of operations, and financial conditions. For example, the Railroad Commission of Texas (RRC) has been developing data associated with seismic activity, particularly such activity related to injection wells used for produced water disposal. In September 2021, the RRC began to limit saltwater disposal in the Midland Basin under what is known as a Seismic Response Action (or SAR) due to increased seismic activity. These developments could result in restriction of disposal wells that could have a material effect on the Company’s capital expenses and operating costs or limit production in certain areas.

RISKS RELATED TO INTERNATIONAL OPERATIONS

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

The Company’s operations outside the U.S. are based primarily in Egypt and the U.K., with significant exploration and appraisal activities offshore Suriname. On a barrel equivalent basis, approximately 41 percent of the Company’s 2021 production was outside the U.S., and approximately 32 percent of the Company’s estimated proved oil and gas reserves as of December 31, 2021, were located outside the U.S. As a result, a significant portion of the Company’s 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, including through prospective or retroactive changes in the laws and regulations applicable to such 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 U.S. affecting foreign trade, including trade sanctions;
- the long-term effects of the U.K.’s 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 the Company currently operates;
- the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the U.S.; and
- difficulties in enforcing the Company’s 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 the Company by another country, the Company's interests could decrease in value or be lost. Even the Company's smaller international assets may affect its overall business and results of operations by distracting management's attention from its more significant assets. Certain regions of the world in which the Company operates 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 the Company's. In an extreme case, such a change could result in termination of contract rights and expropriation of the Company's assets. This could adversely affect the Company's interests and its future profitability.

The impact that future terrorist attacks or regional hostilities, as have occurred in countries and regions in which the Company operates, may have on the oil and gas industry in general and on the Company's 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. The Company may be required to incur significant costs in the future to safeguard its 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 the Company's 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 the Company's assets or resource nationalization, and/or forced renegotiation or modification of the Company's existing contracts with Egyptian General Petroleum Corporation (EGPC), or threats or acts of terrorism could materially and adversely affect the Company's business, financial condition, and results of operations. The Company's operations in Egypt, excluding the impacts of a one-third noncontrolling interest, contributed 22 percent of the Company's 2021 production and accounted for 16 percent of the Company's year-end estimated proved reserves and 20 percent of the Company's estimated discounted future net cash flows.

The Company's operations are sensitive to currency rate fluctuations.

The Company's operations are sensitive to fluctuations in foreign currency exchange rates, particularly between the U.S. dollar and the British pound. The Company's 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 the Company's results of operations, particularly through the weakening of the U.S. dollar relative to other currencies.

RISKS RELATED TO THE HOLDING COMPANY REORGANIZATION

APA, as the parent holding company of Apache, is dependent on the operations and funds of its subsidiaries, including Apache.

As a result of the Holding Company Reorganization APA became the successor issuer to, and parent holding company of, Apache. APA has no business operations of its own, and its only significant assets are the outstanding equity interests of its subsidiaries, including Apache. As a result, APA relies on cash flows from its subsidiaries, including Apache, to pay dividends with respect to APA's common stock and to meet its financial obligations, including to service any debt obligations that the Company may incur from time to time. Legal and contractual restrictions in agreements governing future indebtedness of Apache, as well as Apache's financial condition and future operating requirements, may limit Apache's ability to distribute cash to the Company. If Apache is limited in its ability to distribute cash to the Company, or if Apache's earnings or other available assets of are not sufficient to pay distributions or make loans to the Company in the amounts or at the times necessary for it to pay dividends with respect to its common stock and/or to meet its financial obligations, then the Company's business, financial condition, cash flows, results of operations, and reputation may be materially adversely affected.

The Company may not obtain the anticipated benefits of the reorganization into a holding company structure.

The Company believes that its new operating structure will allow it to focus on running its diverse businesses independently, with the goal of maximizing each of the business' potential. However, the anticipated benefits of the Holding Company Reorganization may not be obtained if circumstances prevent the Company from taking advantage of the strategic and business opportunities that it expects the structure may afford the Company. As a result, the Company may incur the costs of a holding company structure without realizing the anticipated benefits, which could adversely affect the Company's business, financial condition, cash flows, and results of operations.

Management is dedicating significant effort to the new operating structure. These efforts may divert management's focus and resources from the Company's operations, strategic initiatives, or development opportunities, which could adversely affect the Company's prospects, business, financial condition, cash flows, and results of operations.

GENERAL RISK FACTORS

Certain anti-takeover provisions in the Company's charter and Delaware law could delay or prevent a hostile takeover.

The Company's charter authorizes the 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 the Company and any holder of 15 percent or more of APA's outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of the Company that would have been financially beneficial to APA's shareholders.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

The information set forth under "Legal Matters" and "Environmental Matters" in Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K is incorporated herein by reference.

ITEM 4. *MINE SAFETY DISCLOSURES*

None.

PART II

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

APA's common stock, par value $0.625 per share, is traded on the Nasdaq Global Select Market (Nasdaq) under the symbol "APA." The closing price of APA's common stock, as reported by the Nasdaq for January 31, 2022, was $33.21 per share. As of January 31, 2022, there were 346,776,379 shares of APA's common stock outstanding held by approximately 3,300 stockholders of record and 152,000 beneficial owners.

The Company has paid cash dividends on its common stock for 57 consecutive years through December 31, 2021. In the third quarter of 2021, APA's Board of Directors approved an increase in the Company's quarterly dividend per share from $0.025 per share to $0.0625 per share, effective for all dividends payable after September 14, 2021, and further increased the quarterly dividend in the fourth quarter of 2021 to $0.125 per share to be paid on February 22, 2022. When, and if, declared by the Company's Board of Directors, future dividend payments will depend upon the Company's 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 2022 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 APA during 2021.

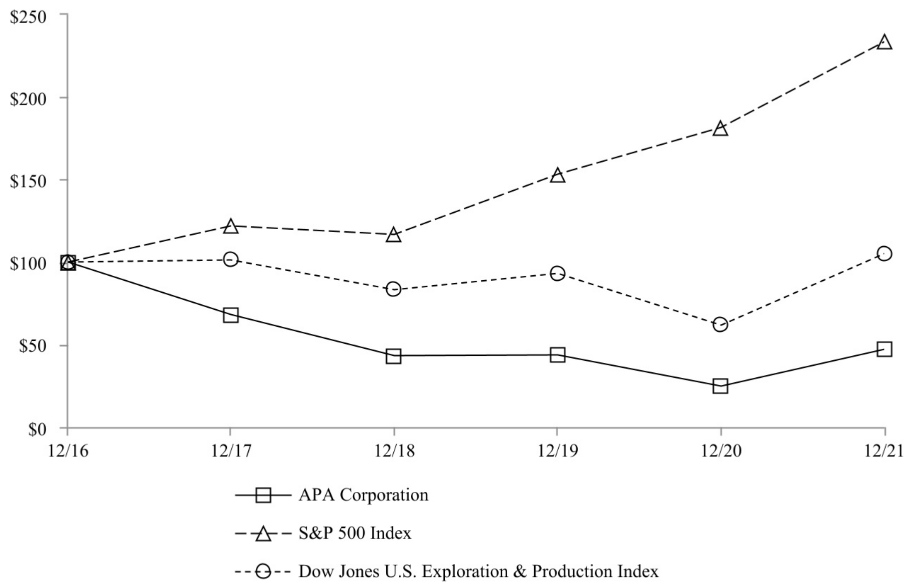
Period	Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 to January 31, 2021	—	$ —	—	40,000,019
February 1 to February 28, 2021	—	—	—	40,000,019
March 1 to March 31, 2021	—	—	—	40,000,019
April 1 to April 30, 2021	—	—	—	40,000,019
May 1 to May 31, 2021	—	—	—	40,000,019
June 1 to June 30, 2021	—	—	—	40,000,019
July 1 to July 31, 2021	—	—	—	40,000,019
August 1 to August 31, 2021	—	—	—	40,000,019
September 1 to September 30, 2021	—	—	—	40,000,019
October 1 to October 31, 2021	12,849,856	26.48	12,849,856	67,150,163
November 1 to November 30, 2021	11,153,840	28.28	11,153,840	55,996,323
December 1 to December 31, 2021	7,200,533	26.58	7,200,533	48,795,790
Total	31,204,229	$ 27.14		

(1) During the fourth quarter of 2018, the Company's Board of Directors authorized the purchase of up to 40 million shares of the Company's common stock. During the fourth quarter of 2021, the Company's Board of Directors authorized the purchase of an additional 40 million shares of the Company's common stock. In both cases, shares may be purchased either in the open market or through privately held negotiated transactions.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's 500 Index (S&P 500 Index) and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 31, 2016, through December 31, 2021. The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among APA Corporation, the S&P 500 Index,
and the Dow Jones U.S. Exploration & Production Index



* $100 invested on 12/31/16 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	2016	2017	2018	2019	2020	2021
APA Corporation	$ 100.00	$ 67.87	$ 43.18	$ 43.63	$ 24.56	$ 46.86
S&P 500 Index	100.00	121.83	116.49	153.17	181.35	233.41
Dow Jones U.S. Exploration & Production Index	100.00	101.30	83.30	92.79	61.57	105.24

ITEM 6. ***SELECTED FINANCIAL DATA***

Omitted.

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

The following discussion relates to APA Corporation (APA or the Company) and its consolidated subsidiaries and should be read together in conjunction with the Company's Consolidated Financial Statements and accompanying notes included in Part IV, Item 15 of this Annual Report on Form 10-K, and the risk factors and related information set forth in Part I, Item 1A and Part II, Item 7A of this Annual Report on Form 10-K. This section of this Annual Report on Form 10-K generally discusses 2021 and 2020 items and year-to-year comparisons between 2021 and 2020. Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 that are not included in this Annual Report on Form 10-K are incorporated by reference to "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of Apache Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2020 (filed with the SEC on February 25, 2021).

On January 4, 2021, Apache Corporation announced plans to implement a holding company reorganization (the Holding Company Reorganization), which was thereafter completed on March 1, 2021. In connection with the Holding Company Reorganization, Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares were automatically converted into equivalent corresponding shares of APA Corporation. Pursuant to the Holding Company Reorganization, APA Corporation became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe.

Overview

APA is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids (NGLs). The Company's upstream business 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). APA also has active exploration and appraisal operations ongoing in Suriname, as well as interests in other international locations that may, over time, result in reportable discoveries and development opportunities. The Company's midstream business (Altus Midstream) is operated by Altus Midstream Company (Nasdaq: ALTM) through its subsidiary Altus Midstream LP (collectively, Altus). Altus owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas.

APA believes energy underpins global progress, and the Company wants to be a part of the conversation and solution as society works to meet growing global demand for reliable and affordable energy. Today, the world faces a dual challenge: To meet growing demand for energy and to do so in a cleaner, more sustainable way. APA believes society can accomplish both and strives to meet those challenges while creating value for all its stakeholders.

The global economy and the energy industry have been deeply impacted by the effects of the coronavirus disease 2019 (COVID-19) pandemic and related governmental actions. Uncertainties in the commodity and financial markets since early 2020 continue to impact oil supply and demand. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to maintain a balanced asset portfolio, including advancement of ongoing exploration and appraisal activities offshore Suriname; (2) to invest for long-term returns over production growth; and (3) to budget conservatively to generate cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and other return of capital to its stakeholders. The Company continues to aggressively manage its cost structure regardless of the oil price environment and closely monitors hydrocarbon pricing fundamentals to reallocate capital as part of its ongoing planning process. For additional detail on the Company's forward capital investment outlook, refer to "Capital and Operational Outlook" below.

During 2021, the Company reported net income attributable to common stock of $973 million, or $2.59 per diluted share, compared to a net loss of $4.9 billion, or $12.86 per diluted share, in 2020. Net income in 2021 benefited from significantly improved commodity prices that had collapsed in the prior year when the COVID-19 pandemic negatively affected economic activity and the oil markets. In 2020, the Company recorded impairments totaling $4.5 billion in connection with fair value assessments stemming from the global crude oil price collapse.

The Company generated $3.5 billion of cash from operating activities in 2021, which was $2.1 billion or 152 percent higher than the prior year. APA's higher operating cash flows for 2021 were driven by higher crude oil and natural gas prices and associated revenues. The Company ended the year with a cash balance of $302 million, up $40 million from year-end 2020, after paying back nearly $1.4 billion of debt during 2021 in an effort to reduce near-term debt maturities and strengthening its balance sheet.

Following this progress and considering the ongoing constructive price environment, the Company initiated a capital return framework for our shareholders, as follows:

- The Company implemented a capital return framework during 2021 for equity holders to participate more directly and materially in cash returns. The Company believes returning 60 percent of cash flow over capital investment creates a good balance for providing near-term cash returns to shareholders while still recognizing the importance of longer-term balance sheet strengthening.

- The Company announced a quarterly dividend increase in the third quarter of 2021 from $0.025 per share to $0.0625 per share and, in the fourth quarter of 2021, announced a further increase to $0.125 per share.

- During the fourth quarter of 2021, the Company's Board of Directors authorized the purchase of up to 40 million shares of the Company's common stock. The Company repurchased approximately 31.2 million of its common shares for $847 million during the fourth quarter of 2021. As of December 31, 2021, the Company had remaining authorization to repurchase up to 48.8 million shares under Company's share repurchase programs.

Operational Highlights

Key operational highlights for the year include:

United States

- Daily boe production from the Company's U.S. assets, which decreased 10 percent from the prior year end, accounted for 59 percent of its total worldwide production during 2021. After halting all drilling and completion activity for most of 2020, in response to completion cost reductions, the Company reinstated two operated completion crews in the Permian Basin in late 2020 to begin completing its backlog of drilled but uncompleted well inventory. In early 2021, the Company re-activated one drilling rig in the Permian Basin and one rig in the Austin Chalk. A second rig was added in the Permian Basin in late June 2021. For 2022, the Company will continue to budget its capital program at levels to fund activity necessary to offset inherent declines in production and proved oil and natural gas reserves.

- On October 11, 2021, the Company announced that it has ended routine flaring in its U.S. onshore operations, achieving one of its announced 2021 environmental, social and governance (ESG) goals three months ahead of schedule. The Company also seeks continuous improvement on its safety performance and protocols, having established key safety indicators and metrics that are rigorously managed and that impact annual incentive compensation Company-wide.
- On October 21, 2021, ALTM announced that it will combine with privately owned BCP Raptor Holdco LP (BCP) in an all-stock transaction. As consideration for the transaction, ALTM will issue 50 million shares of Class C Common Stock (and its subsidiary, Altus Midstream LP, will issue a corresponding number of common units) to BCP's unitholders, which are principally funds affiliated with Blackstone and I Squared Capital. Upon closing of the transaction, APA will own approximately 20 percent of the issued and outstanding common stock of the combined entity. The transaction is expected to close during the first quarter of 2022 following completion of customary closing conditions.

International

- In December 2021, the Egyptian President signed and ratified the previously announced agreement with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation (EGPC) to modernize the terms of the majority of the Company's production-sharing contracts (PSCs), having an effective date of April 1, 2021. The new PSC consolidates 98 percent of gross acreage and 90 percent of gross production into a single concession and refreshes the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool that provides improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all the Company's production covered under the new concession. The changes also simplify the contractual relationship with EGPC, facilitate recovery of prior investment, and update day-to-day operational governance. The Apache entity that is the sole contractor is owned two-thirds by Apache and one-third by Sinopec International Petroleum Exploration and Production Corporation (Sinopec).

- Egypt gross equivalent production decreased 14 percent and net production decreased 6 percent from 2020, primarily a result of natural decline given reduced drilling activity in the past year. The modernized production-sharing agreement did not impact 2021 production since it was ratified at the end of the year. The Company continues to build and enhance its robust drilling inventory in Egypt, supplemented with recent seismic acquisitions and new play concept evaluations, on both new and existing acreage. The Company anticipates increased drilling and workover activity in 2022 as a result of the ratification of the new modernized PSC.
- The North Sea maintained two drilling rigs during 2021. During the year, production was significantly impacted by compressor downtime, extended platform turnaround work, and third-party pipeline outages.
- Following three successful exploration discoveries offshore Suriname on Block 58, in late 2020, the Company commenced drilling a fourth exploration well in the block at the Keskesi prospect. In January 2021, the Company and its partner TotalEnergies (formerly Total S.A.) announced a discovery that confirmed oil in the eastern portion of the block. The Company has subsequently transferred operatorship of Block 58 to TotalEnergies, with exploration and appraisal activities continuing to progress. TotalEnergies holds a 50 percent working interest in Block 58.
- In November 2021, the Company announced a successful flow test and pressure buildup at its Sapakara South appraisal well on Block 58, which continues to improve in outlook as additional information is gathered and processed. Further, in February 2022 the Company and TotalEnergies announced an oil discovery at the Krabdagu-1 (KBD-1) exploration well. KBD-1 is located approximately 18 kilometers southeast of the Sapakara South-1 well. The well was designed to test multiple stacked targets in Maastrichtian and Campanian intervals and encountered approximately 90 meters (295 feet) of net oil pay.

For a more detailed discussion related to the Company's various geographic segments, refer to "Upstream Exploration and Production Properties—Operating Areas" set forth in Part I, Item 1 and 2 of this Annual Report on Form 10-K.

Acquisition and Divestiture Activity

Over the Company's history, it has repeatedly demonstrated the ability to capitalize quickly and decisively on changes in its industry and economic conditions. A key component of this strategy is to continuously review and optimize APA's portfolio of assets in response to these changes. Most recently, the Company has completed a series of divestitures designed to monetize nonstrategic assets and enhance the Company's portfolio in order to allocate resources to more impactful exploration and development opportunities. These divestitures include:

- *Permian Basin Divestiture* In the second quarter of 2021, the Company completed the sale of certain non-core assets in the Central Basin Platform of the Permian Basin for total cash proceeds of $176 million and the assumption of asset retirement obligations of $44 million.
- *U.S. Leasehold Divestitures & Acquisitions* During 2021, the Company completed the sale of other non-core assets and leasehold acreage, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $80 million. Also during 2021, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $9 million.
- *U.S. Leasehold Divestitures & Other* During 2020, the Company completed the sale of certain non-core producing assets and leasehold acreage, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $87 million. The Company also completed certain leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $4 million.
- *Suriname Joint Venture Agreement* In December 2019, the Company entered into a joint venture agreement with TotalEnergies to explore and develop Block 58 offshore Suriname. Under the terms of the agreement, the Company and TotalEnergies each hold a 50 percent working interest in Block 58. The Company operated the drilling of the first four wells and subsequently transferred operatorship of Block 58 to TotalEnergies. In connection with the agreement, the Company received $100 million upon closing in the fourth quarter of 2019 and $79 million upon satisfying certain closing conditions in the first quarter of 2020 for reimbursement of 50 percent of all costs incurred on Block 58 as of December 31, 2019. Key terms of the agreement provide for TotalEnergies to pay a proportionately larger share of appraisal and development costs, which would be recoverable through hydrocarbon participation.

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

Results of Operations

Oil and Gas Production Revenues

The Company’s oil and gas production revenues and respective contribution to total revenues by country are as follows:

	For the Year Ended December 31,					
	2021		2020		2019	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
	($ in millions)					
Oil Revenues:						
United States	$ 1,850	40 %	$ 1,209	39 %	$ 2,098	40 %
Egypt[(1)]	1,806	40 %	1,102	35 %	1,969	38 %
North Sea	929	20 %	795	26 %	1,163	22 %
Total[(1)]	$ 4,585	100 %	$ 3,106	100 %	$ 5,230	100 %
Natural Gas Revenues:						
United States	$ 754	62 %	$ 251	42 %	$ 293	43 %
Egypt[(1)]	270	23 %	280	47 %	295	44 %
North Sea	183	15 %	67	11 %	90	13 %
Total[(1)]	$ 1,207	100 %	$ 598	100 %	$ 678	100 %
NGL Revenues:						
United States	$ 673	95 %	$ 304	91 %	$ 372	91 %
Egypt[(1)]	9	1 %	8	3 %	12	3 %
North Sea	24	4 %	21	6 %	23	6 %
Total[(1)]	$ 706	100 %	$ 333	100 %	$ 407	100 %
Oil and Gas Revenues:						
United States	$ 3,277	50 %	$ 1,764	44 %	$ 2,763	44 %
Egypt[(1)]	2,085	32 %	1,390	34 %	2,276	36 %
North Sea	1,136	18 %	883	22 %	1,276	20 %
Total[(1)]	$ 6,498	100 %	$ 4,037	100 %	$ 6,315	100 %

(1) Includes revenues attributable to a noncontrolling interest in Egypt.

Production

The following table presents production volumes by country:

	For the Year Ended December 31,				
	2021	Increase (Decrease)	2020	Increase (Decrease)	2019
Oil Volumes – b/d:					
United States[5]	75,205	(15)%	88,249	(16)%	105,051
Egypt[3][4]	70,349	(7)%	75,384	(11)%	84,617
North Sea	36,265	(28)%	50,386	1%	49,746
Total	181,819	(15)%	214,019	(11)%	239,414
Natural Gas Volumes – Mcf/d:					
United States[5]	527,461	(6)%	561,731	(12)%	639,580
Egypt[3][4]	263,653	(4)%	274,175	(4)%	285,972
North Sea	38,565	(33)%	57,464	5%	54,642
Total	829,679	(7)%	893,370	(9)%	980,194
NGL Volumes – b/d:					
United States[5]	66,232	(11)%	74,136	8%	68,381
Egypt[3][4]	531	(30)%	754	(19)%	931
North Sea	1,199	(38)%	1,936	11%	1,739
Total	67,962	(12)%	76,826	8%	71,051
BOE per day:[1]					
United States[5]	229,348	(10)%	256,007	(9)%	280,029
Egypt[3][4]	114,821	(6)%	121,834	(9)%	133,209
North Sea[2]	43,892	(29)%	61,899	2%	60,592
Total	388,061	(12)%	439,740	(7)%	473,830

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

(2) Average sales volumes from the North Sea were 44,179 boe/d, 62,157 boe/d, and 59,797 boe/d for 2021, 2020, and 2019, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

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

	2021	2020	2019
Oil (b/d)	134,711	164,104	193,886
Natural Gas (Mcf/d)	586,663	641,069	708,682
NGL (b/d)	854	1,429	1,722

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

	2021	2020	2019
Oil (b/d)	23,504	25,206	28,220
Natural Gas (Mcf/d)	88,409	91,540	95,539
NGL (b/d)	177	251	310

(5) Production volumes per day in the Company’s Alpine High field were as follows:

	2021	2020	2019
Oil (b/d)	1,485	2,718	3,475
Natural Gas (Mcf/d)	258,096	274,279	316,169
NGL (b/d)	22,950	24,942	17,446

Pricing

The following table presents pricing information by country:

	For the Year Ended December 31,				
	2021	Increase (Decrease)	2020	Increase (Decrease)	2019
Average Oil Price - Per barrel:					
United States	$ 67.37	80%	$ 37.42	(32)%	$ 54.71
Egypt	70.33	76%	39.95	(37)%	63.76
North Sea	69.67	62%	42.88	(34)%	65.10
Total	68.97	74%	39.60	(34)%	60.05
Average Natural Gas Price - Per Mcf:					
United States	$ 3.92	221%	$ 1.22	(3)%	$ 1.26
Egypt	2.81	1%	2.79	(1)	2.83
North Sea	12.96	306%	3.19	(29)%	4.48
Total	3.99	118%	1.83	(4)%	1.90
Average NGL Price - Per barrel:					
United States	$ 27.85	148%	$ 11.21	(25)%	$ 14.95
Egypt	48.84	75%	27.83	(18)%	33.87
North Sea	54.30	83%	29.73	(19)%	36.83
Total	28.48	141%	11.84	(25)%	15.74

Crude Oil Prices A substantial portion of the Company’s crude oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of the Company’s control. Average realized crude oil prices for 2021 were up 74 percent compared to 2020, a direct result of the rising benchmark oil prices over the past year. Crude oil prices realized in 2021 averaged $68.97 per barrel.

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

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

- The Company predominantly sells its natural gas production within the U.S., including to U.S. LNG export facilities, although a portion is sold to markets in Mexico. Most of the Company’s U.S. natural gas is sold on a monthly or daily basis at either monthly or daily index-based prices. The Company’s U.S. realizations averaged $3.92 per Mcf in 2021, up from $1.22 per Mcf in 2020.
- In Egypt, the Company’s natural gas 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. Overall, the Company’s Egypt operations averaged $2.81 per Mcf in 2021, a 1 percent increase from 2020.
- Natural gas from the North Sea Beryl field is processed through the SAGE gas plant. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The Company’s North Sea operations averaged $12.96 per Mcf in 2021, a 306 percent increase from an average of $3.19 per Mcf in 2020.

NGL Prices The Company's U.S. NGL production, which accounted for 97 percent of the Company's total 2021 NGL production, is sold under contracts with prices at market indices based on Gulf Coast supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Crude Oil Revenues

Crude oil revenues for 2021 totaled $4.6 billion, a $1.5 billion increase from the 2020 total of $3.1 billion. A 74 percent increase in average realized prices increased 2021 revenues by $2.3 billion compared to 2020, while 15 percent lower average daily production decreased revenues by $825 million. Average daily production in 2021 was 182 Mb/d, with prices averaging $68.97 per barrel. Crude oil sales accounted for 71 percent of the Company's 2021 oil and gas production revenues and 47 percent of its worldwide production.

The Company's worldwide crude oil production decreased 32 Mb/d compared to 2020, primarily a result of production decline across all countries driven by reduced drilling activity in the prior year, and extended operational downtime and platform turnaround work in the North Sea.

Natural Gas Revenues

Natural gas revenues for 2021 totaled $1,207 million, a $609 million increase from the 2020 total of $598 million. A 118 percent increase in average realized prices increased 2021 revenues by $705 million compared to 2020, while 7 percent lower average daily production decreased revenues by $96 million. Average daily production in 2021 was 830 MMcf/d, with prices averaging $3.99 per Mcf. Natural gas sales accounted for 18 percent of the Company's 2021 oil and gas production revenues and 36 percent of its worldwide production.

The Company's worldwide natural gas production decreased 64 MMcf/d compared to 2020, primarily a result of production decline across all countries, impacts of winter storms in the U.S., and extended operational downtime and platform turnaround work in the North Sea.

NGL Revenues

NGL revenues for 2021 totaled $706 million, a $373 million increase from the 2020 total of $333 million. A 141 percent increase in average realized prices increased 2021 revenues by $467 million compared to 2020, while 12 percent lower average daily production decreased revenues by $94 million. Average daily production in 2021 was 68 Mb/d, with prices averaging $28.48 per barrel. NGL sales accounted for 11 percent of the Company's 2021 oil and gas production revenues and 17 percent of its worldwide production.

The Company's worldwide NGL production decreased 9 Mb/d compared to 2020, primarily a result of production decline across all countries and the impacts of winter storms in the U.S.

Altus Midstream Revenues

The Company beneficially owns approximately 79 percent of ALTM's outstanding voting common stock. Altus owns and operates a midstream energy asset network in the Permian Basin of West Texas primarily to service the Company's production from its Alpine High resource play, which commenced production in May 2017. On October 21, 2021, ALTM announced that it will combine with privately owned BCP in an all-stock transaction, and APA's ownership in ALTM will be reduced from approximately 79 percent to approximately 20 percent. The transaction is expected to close during the first quarter of 2022, following completion of customary closing conditions.

Altus Midstream primarily generates revenue by providing fee-based natural gas gathering, compression, processing, and transmission services. For the years ended December 31, 2021 and 2020, Altus Midstream's service revenues generated through its fee-based contractual arrangements with the Company totaled $127 million and $145 million, respectively. These affiliated revenues are eliminated upon consolidation. The decrease in revenue compared to the prior year was primarily driven by lower natural gas throughput volumes processed by Altus for the Company's Alpine High production.

Purchased Oil and Gas Sales

Purchased oil and gas sales represent volumes primarily attributable to transport, fuel, and physical in-basin gas purchases that were sold by the Company to fulfill natural gas takeaway obligations. Sales related to these purchased volumes increased $1.1 billion for the year ended December 31, 2021 from $398 million to $1.5 billion. Purchased oil and gas sales were offset by associated purchase costs of $1.6 billion and $357 million for the years ended December 31, 2021 and 2020, respectively. The increase is the result of sales volume growth associated with additional transport capacity and a more than doubling of the average gas sales price.

Operating Expenses

The table below presents a comparison of the Company's operating expenses for the years ended December 31, 2021, 2020, and 2019. All operating expenses include costs attributable to a noncontrolling interest in Egypt and Altus.

	For the Year Ended December 31,		
	2021	**2020**	**2019**
		(In millions)	
Lease operating expenses	$ 1,241	$ 1,127	$ 1,447
Gathering, processing, and transmission	264	274	306
Purchased oil and gas costs	1,580	357	142
Taxes other than income	204	123	207
Exploration	155	274	805
General and administrative	376	290	406
Transaction, reorganization, and separation	22	54	50
Depreciation, depletion, and amortization:			
Oil and gas property and equipment	1,255	1,643	2,512
Gathering, processing, and transmission assets	64	76	105
Other assets	41	53	63
Asset retirement obligation accretion	113	109	107
Impairments	208	4,501	2,949
Financing costs, net	514	267	462

Lease Operating Expenses (LOE)

LOE includes several key components, such as direct operating costs, repairs and maintenance, and workover costs. Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as rig rates, labor, boats, helicopters, materials, and supplies. Crude oil, which accounted for 47 percent of the Company's total 2021 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

During 2021, LOE increased $114 million, or 10 percent, compared to 2020. On a per-boe basis, LOE increased $1.75, or 25 percent, compared to 2020, from $7.00 per boe to $8.75 per boe. The increase in costs was driven by maintenance and turnaround costs in the North Sea, higher-priced emissions credits purchased in association with North Sea production, increased workover activity in the U.S., operating costs trending with commodity prices, inflation impacts, and overall higher labor costs that were heavily impacted by mark-to-market adjustments for stock-based compensation.

Gathering, Processing, and Transmission (GPT)

GPT expenses include amounts paid to third-party carriers and to Altus Midstream for gathering and transmission services for the Company's upstream natural gas production associated with its Alpine High play. GPT expenses also include midstream operating costs incurred by Altus Midstream. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Third-party processing and transmission costs	$ 232	$ 236	$ 250
Midstream service affiliate costs	128	143	134
Upstream processing and transmission costs	360	379	384
Midstream operating expenses	32	38	56
Intersegment eliminations	(128)	(143)	(134)
Total Gathering, processing, and transmission	$ 264	$ 274	$ 306

GPT costs decreased $10 million compared to 2020. Third-party processing and transmission costs decreased $4 million, primarily driven by a decrease in contracted pricing and lower processed volumes. Midstream service affiliate costs decreased $15 million compared to 2020, primarily driven by lower throughput of natural gas volumes at Alpine High. Midstream operating expenses, incurred primarily by Altus, decreased $6 million compared to 2020, driven by continued improvements in operational efficiency as a result of transitioning from mechanical refrigeration units to Altus' centralized Diamond cryogenic complex. The transition resulted in decreases in contract labor, equipment rentals, and chemical expenses.

Purchased Oil and Gas Costs

Purchased oil and gas costs increased $1.2 billion compared to 2020, and were primarily offset by associated sales totaling $1.5 billion for the year ended 2021, as further discussed above.

Taxes Other Than Income

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

Taxes other than income increased $81 million compared to 2020, primarily from higher severance taxes driven by higher commodity prices.

Exploration Expenses

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

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Unproved leasehold impairments	$ 31	$ 101	$ 619
Dry hole expenses	66	110	57
Geological and geophysical expenses	18	20	59
Exploration overhead and other	40	43	70
Total Exploration	$ 155	$ 274	$ 805

Exploration expenses decreased $119 million compared to 2020. Unproved leasehold impairments were $70 million lower than the prior year due to improved commodity prices and increased drilling plans in the U.S. Dry hole expense decreased $44 million, geological and geophysical expenses decreased $2 million, and exploration overhead and other expenses decreased $3 million compared to 2020, primarily resulting from decreased exploration activities compared to the prior year.

General and Administrative (G&A) Expenses

G&A expenses increased $86 million compared to 2020, primarily driven by higher cash-based stock compensation expense resulting from an increase in the Company's stock price compared to the prior year, partially offset by lower overhead driven by organizational redesign efforts during 2019 and 2020.

Transaction, Reorganization, and Separation (TRS) Costs

TRS costs decreased $32 million compared to 2020, primarily driven by costs associated with the Company's reorganization efforts incurred primarily in the prior year.

In recent years, the Company has streamlined its portfolio through strategic divestitures and centralized certain operational activities in an effort to capture greater efficiencies and cost savings through shared services. During the second half of 2019, management initiated a comprehensive redesign of the Company's organizational structure and operations that it believes will better position the Company to be competitive for the long-term and further reduce recurring costs. Reorganization efforts were substantially completed in 2020; however, additional reorganization costs related to ongoing consulting and separation activities in the Company's international operations were incurred during 2021.

Depreciation, Depletion and Amortization (DD&A)

DD&A expenses on the Company's oil and gas property for the year ended December 31, 2021 decreased $388 million compared to 2020. The Company's oil and gas property DD&A rate decreased $1.35 per boe in 2021 compared to 2020, from $10.20 per boe to $8.85 per boe. The decrease was driven by lower production volumes and lower asset property balances associated with proved property impairments recorded during the first quarter of 2020. DD&A expense on the Company's GPT depreciation decreased $12 million compared to 2020, driven by impairment charges recorded against the carrying value of the Company's GPT facilities in Egypt during the first quarter of 2020.

Impairments

During 2021, the Company recorded asset impairments totaling $208 million. The charges include $160 million for Altus' equity method interest in EPIC, as part of Altus' review of the fair value of its assets in relation to the announced BCP Business Combination, $26 million in connection with inventory valuations in Egypt, and $22 million in connection with inventory valuations and expected equipment dispositions in the North Sea.

During 2020, the Company recorded asset impairments in connection with fair value assessments totaling $4.5 billion, including $4.3 billion for oil and gas proved properties in the U.S, Egypt, and the North Sea, $68 million for GPT facilities in Egypt, $87 million for goodwill in Egypt, and $27 million for inventory and other miscellaneous assets, including lease assets and charges for the early termination of drilling rig leases.

The following table presents a summary of asset impairments recorded for 2021, 2020, and 2019:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Oil and gas proved property	$ —	$ 4,319	$ 1,484
GPT facilities	—	68	1,295
Equity method interests	160	—	—
Divested unproved properties and leasehold	—	—	149
Goodwill	—	87	—
Inventory and other	48	27	21
Total Impairments	$ 208	$ 4,501	$ 2,949

Financing Costs, Net

Financing costs incurred during the period comprised the following:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Interest expense	$ 419	$ 438	$ 430
Amortization of debt issuance costs	8	8	7
Capitalized interest	(9)	(12)	(37)
Loss (gain) on extinguishment of debt	104	(160)	75
Interest income	(8)	(7)	(13)
Total Financing costs, net	$ 514	$ 267	$ 462

Net financing costs increased $247 million compared to 2020, primarily the result of a $104 million loss on extinguishment of debt during 2021 and a $160 million gain on extinguishment of debt during 2020.

Provision for Income Taxes

Income tax expense increased $514 million from $64 million during 2020 to $578 million during 2021. The Company's year-to-date 2021 effective income tax rate was primarily impacted by asset impairments and a decrease in the amount of valuation allowance against its U.S. deferred tax assets. During 2020, the Company's effective income tax rate was primarily impacted by oil and gas asset impairments, a goodwill impairment, and an increase in the amount of valuation allowance against its U.S. deferred tax assets.

The Company recorded a full valuation allowance against its U.S. net deferred tax assets and will continue to maintain a full valuation allowance on its U.S. net deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of this allowance. For additional information regarding income taxes, refer to Note 10—Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company and its subsidiaries are subject to U.S. federal income tax as well as income or capital taxes in various state and foreign jurisdictions. The Company's tax reserves are related to tax years that may be subject to examination by the relevant taxing authority. The Company is currently under audit by the Internal Revenue Service (IRS) for the 2014-2017 tax years and is also under audit in various states and foreign jurisdictions as part of its normal course of business.

Capital and Operational Outlook

The Company continues to prudently manage its capital program against a volatile price environment and the prolonged effects of the COVID-19 pandemic. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to maintain a balanced asset portfolio, including advancement of ongoing exploration and appraisal activities offshore Suriname; (2) to invest for long-term returns over production growth; and (3) to budget conservatively to generate cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and return of capital to its stakeholders.

The Company's 2022 capital program will maintain a similar investment approach to the prior year, with upstream capital investment budgeted at approximately $1.6 billion. This budget includes small changes to the timing of rig count increases in Egypt and the U.S. as well as updated views on costs and inflation. This amount also includes approximately $200 million for exploration and appraisal activities, primarily in Suriname. In 2023 and 2024, the total capital budget is anticipated to increase slightly despite a relatively unchanged activity set, given expectations of continued inflationary pressure.

Based on this planned capital activity, the Company anticipates 2022 worldwide production levels will be similar to 2021, after adjusting for divestments. Egypt gross production is expected to increase through the year with higher rig activity, while Egypt net production will be additionally benefited from the effects of the modernized PSC terms. The Company anticipates moderate production declines in the U.S. compared to 2021 given gradual increases in activity levels over the past year and timing of completions.

At current strip pricing, the Company expects to generate significant cash flow over this capital activity budget. The Company's commitment to return capital to shareholders over the next three years will remain unchanged.

The Company's diversified global portfolio provides the ability to quickly optimize capital allocation as market conditions change. The current uncertainties associated with the COVID-19 pandemic, however, are still evolving and may become more severe and complex. As a result, the COVID-19 pandemic may still materially and adversely affect the Company's results in a manner that is either not currently known or that the Company does not currently consider to be a significant risk to its business. For additional information about the business risks relating to the COVID-19 pandemic and related governmental actions, refer to Part I, Item 1A—Risk Factors of this Annual Report on Form 10-K.

Separate from the Company's upstream oil and gas activities, capital spending for Altus' gathering and processing assets totaled $3 million in 2021, down from $28 million in 2020 when a majority of the midstream infrastructure construction was completed. Altus management believes its existing gathering, processing, and transmission infrastructure capacity is capable of fulfilling its midstream contracts to service the Company's production from Alpine High and any third-party customers.

Additionally, during the years ended December 31, 2021 and 2020, Altus made cash contributions totaling $28 million and $327 million, respectively, for its Equity Method Interest Pipelines that are all currently in service. Altus estimates it will incur minimal capital contributions during 2022 for its equity interest in these joint venture pipelines. Based on Altus management's current financial plan and related assumptions prior to closing the BCP Business Combination, Altus believes that cash from operations, a reduced capital program for its midstream infrastructure, and distributions from Equity Method Interests will generate cash flows in excess of capital expenditures and the amount required to fund Altus' planned quarterly dividend and quarterly payments to the holders of Altus Midstream LP's Series A Cumulative Redeemable Preferred Units (Preferred Units) during 2022.

For further information on the Equity Method Interest Pipelines, refer to Note 6—Equity Method Interests in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Capital Resources and Liquidity

Operating cash flows are the Company's primary source of liquidity. The Company's short-term and long-term operating cash flows are impacted by highly volatile commodity prices, as well as production costs and sales volumes. Significant changes in commodity prices impact the Company's revenues, earnings, and cash flows. These changes potentially impact the Company's liquidity if costs do not trend with related changes in commodity prices. Historically, costs have trended with commodity prices, albeit on a lag. Sales volumes also impact cash flows; however, they have a less volatile impact in the short term.

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

For the year ended December 31, 2021, the Company recognized upward reserve revisions of approximately 10 percent of its year-end 2020 estimated proved reserves as a result of improved commodity prices compared to negative reserve revisions of approximately 7 percent in the prior year as a result of lower commodity prices. The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2021, 2020, and 2019, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 18—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

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

The Company may also elect to utilize available cash on hand, committed subsidiary borrowing capacity, access to both debt and equity capital markets, or proceeds from the sale of nonstrategic assets for all other liquidity and capital resource needs.

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

Sources and Uses of Cash

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

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 3,496	$ 1,388	$ 2,867
Proceeds from Apache credit facility, net	392	150	—
Proceeds from Altus credit facility, net	33	228	396
Proceeds from asset divestitures	256	166	718
Fixed-rate debt borrowings	—	1,238	989
Redeemable noncontrolling interest - Altus Preferred Unit limited partners	—	—	611
Other	23	—	—
	4,200	3,170	5,581
Uses of Cash and Cash Equivalents:			
Additions to oil and gas property[(1)]	1,101	1,270	2,594
Additions to Altus gathering, processing, and transmission facilities[(1)]	3	28	327
Leasehold and property acquisitions	9	4	40
Contributions to Altus equity method interests	28	327	501
Acquisition of Altus equity method interests	—	—	671
Payments on fixed-rate debt	1,795	1,243	1,150
Dividends paid	52	123	376
Distributions to noncontrolling interest - Egypt	279	91	305
Distributions to Altus Preferred Unit limited partners	46	23	—
Shares repurchased	847	—	—
Other	—	46	84
	4,160	3,155	6,048
Increase (decrease) in cash and cash equivalents	$ 40	$ 15	$ (467)

(1) The table presents capital expenditures on a cash basis; therefore, the amounts may differ from those discussed elsewhere in this Annual Report on Form 10-K, which include accruals.

Sources of Cash and Cash Equivalents

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

Net cash provided by operating activities for the year ended December 31, 2021 totaled $3.5 billion, up $2.1 billion from the year ended December 31, 2020, primarily the result of higher commodity prices compared to the prior year.

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

Proceeds from Apache Credit Facility, Net As of December 31, 2021 and 2020, Apache had outstanding borrowings of $542 million and $150 million, respectively, under its credit facility, which is classified as long-term debt.

Proceeds from Altus Credit Facility, Net The construction of Altus' gathering and processing assets and the associated equity interests in the Equity Method Interest Pipelines has historically required capital expenditures in excess of Altus' cash on hand and operational cash flows. During the years ended December 31, 2021 and 2020, Altus Midstream LP borrowed $33 million and $228 million, respectively, under its revolving credit facility to meet this shortfall. With the midstream infrastructure complete and all of the Equity Method Interest Pipelines now in service, the Company anticipates that Altus' existing capital resources will be sufficient to fund its continuing obligations and dividend program.

Proceeds from Asset Divestitures The Company received $256 million and $166 million in proceeds from the divestiture of certain non-core assets during the years ended December 31, 2021 and 2020, respectively. For more information regarding the Company's acquisitions and divestitures, refer to Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements in Part IV set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Fixed-Rate Debt Borrowings On August 17, 2020, Apache closed offerings of $1.25 billion in aggregate principal amount of senior unsecured notes, comprised of $500 million in aggregate principal amount of 4.625% notes due 2025 and $750 million in aggregate principal amount of 4.875% notes due 2027. The senior unsecured notes are redeemable at any time, in whole or in part, at Apache's option, at the applicable redemption price. The net proceeds from the sale of the notes were used to purchase certain outstanding notes in cash tender offers, repay a portion of outstanding borrowings under Apache's senior revolving credit facility, and for general corporate purposes.

Redeemable Noncontrolling Interest - Altus Preferred Unit Limited Partners On June 12, 2019, Altus Midstream LP issued and sold Series A Cumulative Redeemable Preferred Units for an aggregate issue price of $625 million in a private offering exempt from the registration requirements of the Securities Act of 1933, as amended. Altus Midstream LP received approximately $611 million in cash proceeds from the sale after deducting transaction costs and discounts to certain purchasers. For more information, refer to Note 13—Redeemable Noncontrolling Interest - Altus in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Uses of Cash and Cash Equivalents

Additions to Upstream Oil & Gas Property Exploration and development cash expenditures were $1.1 billion and $1.3 billion for the years ended December 31, 2021 and 2020, respectively. The decrease in capital investment is reflective of the Company's capital program, which was reduced early in 2020 to align with anticipated operating cash flows following the collapse of commodity prices stemming from the COVID-19 pandemic. The Company operated an average of 13 drilling rigs during 2021, compared to an average of 12 drilling rigs during 2020.

Additions to Altus Gathering, Processing, and Transmission (GPT) Facilities The Company's cash expenditures for GPT facilities totaled $3 million and $28 million during 2021 and 2020, respectively, nearly all comprising midstream infrastructure expenditures incurred by Altus, which were substantially completed as of December 31, 2019. Altus management believes its existing GPT infrastructure capacity is capable of fulfilling its midstream contracts to service the Company's production from Alpine High and any third-party customers.

Leasehold and Property Acquisitions During 2021 and 2020, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $9 million and $4 million, respectively.

Contributions to Altus Equity Method Interests Altus contributed $28 million and $327 million in cash during 2021 and 2020, respectively, for equity interests in the Equity Method Interest Pipelines. For more information regarding the Company's equity method interests, refer to Note 6—Equity Method Interests in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Payments on Fixed-Rate Debt During 2021, Apache closed cash tender offers for certain outstanding notes issued under its indentures, accepting for purchase $1.7 billion aggregate principal amount of notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $1.8 billion reflecting principal, premium to par, and accrued and unpaid interest. The Company recognized a $105 million loss on extinguishment of debt, including $11 million of unamortized debt discount and issuance costs, in connection with the note purchases.

During 2021, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $22 million for an aggregate purchase price of $20 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $2 million. The Company recognized a $1 million net gain on extinguishment of debt as part of these transactions.

During 2020, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $588 million for an aggregate purchase price of $428 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $168 million. These repurchases resulted in a $158 million net gain on extinguishment of debt. The net gain includes an acceleration of related discount and debt issuance costs. Additionally, on November 3, 2020, Apache redeemed the remaining $183 million of outstanding 3.625% senior notes due February 1, 2021 at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The repurchases were financed by borrowings under Apache's revolving credit facility.

Also during 2020, Apache closed cash tender offers for certain outstanding notes. Apache accepted for purchase $644 million aggregate principal amount certain notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $644 million, reflecting principal, aggregate discount to par of $38 million, early tender premium of $32 million, and accrued and unpaid interest of $6 million. The Company recorded a net gain of $2 million on extinguishment of debt, including an acceleration of unamortized debt discount and issuance costs, in connection with the note purchases.

The Company expects that Apache will continue to reduce debt outstanding under its indentures from time to time.

Dividends The Company paid $52 million and $123 million during the years ended December 31, 2021 and 2020, respectively, for dividends on its common stock. In the first quarter of 2020, the Company's Board of Directors approved a reduction in the Company's quarterly dividend per share from $0.25 per share to $0.025 per share, effective for all dividends payable after March 12, 2020. During the third quarter of 2021, the Company's Board of Directors approved an increase in its quarterly dividend per share from $0.025 to $0.0625, and in the fourth quarter of 2021, approved a further increase to its quarterly dividend to $0.125 per share.

Distributions to Noncontrolling Interest - Egypt Sinopec holds a one-third minority participation interest in the Company's oil and gas operations in Egypt. The Company paid $279 million and $91 million during the years ended December 31, 2021 and 2020, respectively, in cash distributions to Sinopec.

Distributions to Altus Preferred Units limited partners Altus Midstream LP paid $46 million and $23 million in cash distributions to its limited partners holding Preferred Units during the years ended December 31, 2021 and 2020, respectively. For more information regarding the Preferred Units, refer to Note 13—Redeemable Noncontrolling Interest - Altus in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Liquidity

The following table presents a summary of the Company's key financial indicators as of December 31:

	2021	2020
	(In millions)	
Cash and cash equivalents	$ 302	$ 262
Total debt - Apache	6,853	8,148
Total debt - Altus	657	624
Total equity (deficit)	(717)	(645)
Available committed borrowing capacity - Apache	2,426	2,944
Available committed borrowing capacity - Altus	141	176

Cash and Cash Equivalents As of December 31, 2021, the Company had $302 million in cash and cash equivalents, of which approximately $132 million was held by Altus. The majority of the Company's cash is invested in highly liquid, investment-grade instruments with maturities of three months or less at the time of purchase.

Debt As of December 31, 2021, the Company had $7.5 billion in total debt outstanding, which consisted of notes, debentures, credit facility borrowings, and finance lease obligations. Future interest payments on the fixed-rate notes and debentures are approximately $4.7 billion. As of December 31, 2021, current debt included $213 million carrying value of 3.25% senior notes due April 15, 2022 and $2 million of finance lease obligations. On January 18, 2022, Apache redeemed the remaining $213.5 million of outstanding 3.25% senior notes due April 15, 2022 at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The redemption was financed by borrowing under Apache's revolving credit facility.

Committed Credit Facilities In March 2018, Apache entered into a revolving credit facility with commitments totaling $4.0 billion. In March 2019, the term of this facility was extended by one year to March 2024 (subject to Apache's remaining one-year extension option) pursuant to Apache's exercise of an extension option. Apache can increase commitments up to $5.0 billion by adding new lenders or obtaining the consent of any increasing existing lenders. The facility includes a letter of credit subfacility of up to $3.0 billion, of which $2.08 billion was committed as of December 31, 2021. The facility is for general corporate purposes. Letters of credit are available for security needs, including in respect of North Sea decommissioning obligations. The facility has no collateral requirements, is not subject to borrowing base redetermination, and has no drawdown restrictions or prepayment obligations in the event of a decline in credit ratings.

As of December 31, 2021, there were $542 million of borrowings and an aggregate £748 million and $20 million in letters of credit outstanding under this facility. As of December 31, 2020, there were $150 million of borrowings and an aggregate £633 million and $40 million in letters of credit outstanding under this facility. The outstanding letters of credit denominated in pounds were issued to support North Sea decommissioning obligations, the terms of which required such support after Standard & Poor's reduced Apache's credit rating from BBB to BB+ on March 26, 2020.

At Apache's option, the interest rate per annum for borrowings under the 2018 facility is either a base rate, as defined, plus a margin, or the London Inter-bank Offered Rate (LIBOR), plus a margin. Apache also pays quarterly a facility fee at a per annum rate on total commitments. The margins and the facility fee vary based upon Apache's senior long-term debt rating. At December 31, 2021, the base rate margin was 0.5 percent, the LIBOR margin was 1.50 percent, and the facility fee was 0.25 percent. A commission is payable quarterly to lenders on the face amount of each outstanding letter of credit at a per annum rate equal to the LIBOR margin then in effect. Customary letter of credit fronting fees and other charges are payable to issuing banks.

The financial covenants of the credit facility require Apache to maintain an adjusted debt-to-capital ratio of not greater than 60 percent at the end of any fiscal quarter. For purposes of this calculation, capital excludes the effects of non-cash write-downs, impairments, and related charges occurring after June 30, 2015. At December 31, 2021, Apache's debt-to-capital ratio as calculated under the credit facility was 28 percent. The 2018 facility's negative covenants restrict the ability of Apache and its subsidiaries to create liens securing debt on their hydrocarbon-related assets, with exceptions for liens typically arising in the oil and gas industry; liens securing debt incurred to finance the acquisition, construction, improvement, or capital lease of assets, provided that such debt, when incurred, does not exceed the subject purchase price and costs, as applicable, and related expenses; liens on subsidiary assets located outside of the United States and Canada; and liens arising as a matter of law, such as tax and mechanics' liens. Apache also may incur liens on assets if debt secured thereby does not exceed 15 percent of Apache's consolidated net tangible assets, or approximately $1.9 billion as of December 31, 2021. Negative covenants also restrict Apache's ability to merge with another entity unless it is the surviving entity, dispose of substantially all of its assets, and guarantee debt of non-consolidated entities in excess of the stated threshold.

In November 2018, Altus Midstream LP entered into a revolving credit facility for general corporate purposes that matures in November 2023 (subject to Altus Midstream LP's two, one-year extension options). The agreement for this facility, as amended, provides aggregate commitments from a syndicate of banks of $800 million. All aggregate commitments include a letter of credit subfacility of up to $100 million and a swingline loan subfacility of up to $100 million. Altus Midstream LP may increase commitments up to an aggregate $1.5 billion by adding new lenders or obtaining the consent of any increasing existing lenders. As of December 31, 2021, there were $657 million of borrowings and a $2 million letter of credit outstanding under this facility. As of December 31, 2020, there were $624 million of borrowings and no letters of credit outstanding under this facility. The Altus Midstream LP credit facility is unsecured and is not guaranteed by APA or any of its subsidiaries, including Apache.

The agreement for Altus Midstream LP's credit facility, as amended, restricts distributions in respect of capital to Apache and other unit holders in certain circumstances. Unless the Leverage Ratio is less than or equal to 4.00:1.00, the agreement limits such distributions to $30 million per calendar year until either (i) the consolidated net income of Altus Midstream LP and its restricted subsidiaries, as adjusted pursuant to the agreement, for three consecutive calendar months equals or exceeds $350 million on an annualized basis or (ii) Altus Midstream LP has a specified senior long-term debt rating; in addition, before the occurrence of one of those two events, the Leverage Ratio must be less than or equal to 5.00:1.00. In no event can any distribution be made that would, after giving effect to it on a pro forma basis, result in a Leverage Ratio greater than (i) 5.00:1.00 or (ii) for a specified period after a qualifying acquisition, 5.50:1.00. The Leverage Ratio is the ratio of (1) the consolidated indebtedness of Altus Midstream LP and its restricted subsidiaries to (2) EBITDA (as defined in the agreement) of Altus Midstream LP and its restricted subsidiaries for the 12-month period ending immediately before the determination date. The Leverage Ratio as of December 31, 2021 was less than 4.00:1.00.

The terms of Altus Midstream LP's Preferred Units also contain certain restrictions on distributions in respect of capital, including the common units held by Altus Midstream Company and any other units that rank junior to the Preferred Units with respect to distributions or distributions upon liquidation. Refer to Note 13—Redeemable Noncontrolling Interest - Altus in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K for further information. In addition, the amount of any cash distributions to Altus Midstream LP by any entity in which it has an interest accounted for by the equity method is subject to such entity's compliance with the terms of any debt or other agreements by which it may be bound, which in turn may impact the amount of funds available for distribution by Altus Midstream LP to its partners.

There are no clauses in either the agreement for Apache's 2018 credit facility or for Altus Midstream LP's 2018 credit facility that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes. These agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, each agreement allows the lenders to accelerate payment maturity and terminate lending and issuance commitments for nonpayment and other breaches, and if a borrower or any of its subsidiaries defaults on other indebtedness in excess of the stated threshold, is insolvent, or has any unpaid, non-appealable judgment against it for payment of money in excess of the stated threshold. Lenders may also accelerate payment maturity and terminate lending and issuance commitments under the applicable agreement if Apache or Altus Midstream LP, as applicable, undergoes a specified change in control or any borrower has specified pension plan liabilities in excess of the stated threshold. Each of Apache and Altus Midstream LP was in compliance with the terms of its 2018 credit facility as of December 31, 2021.

There is no assurance of the terms upon which potential lenders under future credit facilities will make loans or other extensions of credit available to Apache or its subsidiaries or the composition of such lenders.

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

Commercial Paper Program As of December 31, 2020, no commercial paper was outstanding. Apache did not use its commercial paper program during 2021 and terminated the program during the third quarter of 2021.

Contractual Obligations

Purchase Obligations From time to time, the Company enters into agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, drilling work program commitments and agreements to secure capacity rights on third-party pipelines. As of December 31, 2021, the Company had contractual obligations totaling $4.9 billion, of which $1.2 billion is related to U.S. firm transportation contracts and $3.5 billion is related to the new PSC with the EGPC. Under terms agreed to in the modernized PSC, the Company committed to spend a minimum of $3.5 billion on exploration, development, and operating activities by March 31, 2026. The Company believes it will be able to satisfy this obligation within its current exploration and development program.

Leases In the normal course of business, the Company enters into various lease agreements for real estate, drilling rigs, vessels, aircrafts, and equipment related to its exploration and development activities, which are typically classified as operating leases under the provisions of Financial Accounting Standards Board ASC Topic 842 (Leases). As of December 31, 2021, the Company had net minimum commitments of $272 million and $42 million for operating and finance leases, respectively.

For additional information regarding these obligations, refer to Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

For information regarding the Company's liability for dismantlement, abandonment, and restoration costs of oil and gas properties or pension or postretirement benefit obligations, refer to Notes 8—Asset Retirement Obligation and Note 12—Retirement and Deferred Compensation Plans in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. The Company's management believes that it has adequately reserved for its contingent obligations, including approximately $2 million for environmental remediation and approximately $84 million for various contingent legal liabilities. For a detailed discussion of the Company's lease obligations, purchase obligations, environmental and legal contingencies, and other commitments, please see Note 11—Commitments and Contingencies and Note 12—Retirement and Deferred Compensation Plans in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

As further described above under "Capital and Operational Outlook," Altus Midstream LP and/or its subsidiaries have equity ownership in four Equity Method Interest Pipelines. Altus Midstream LP and/or its subsidiaries may be required to fund future capital expenditures for its equity interest share in the development of the applicable pipeline. Altus estimates that it will incur minimal capital contributions for its equity interests in these joint venture pipelines during 2022.

With respect to oil and gas operations in the Gulf of Mexico, the Bureau of Ocean Energy Management (BOEM) 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 the NTL was paused in mid-2017 and is currently listed on BOEM's website as "rescinded," if reinstated, the NTL will likely require that the Company provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to the Company's current ownership interests in various Gulf of Mexico leases. The Company is working closely with BOEM to make arrangements for the provision of such additional required security, if such security becomes necessary under the NTL. Additionally, the Company is not able to predict the effect that these changes might have on counterparties to which the Company has sold Gulf of Mexico assets or with whom the Company 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.

Potential Decommissioning Obligations on Sold Properties

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

In 2013, Apache sold its GOM Shelf operations and properties and its GOM operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Under the terms of the purchase agreement, Apache received cash consideration of $3.75 billion and Fieldwood assumed the obligation to decommission the properties held by GOM Shelf and the properties acquired from Apache and its other subsidiaries (collectively, the Legacy GOM Assets). In respect of such abandonment obligations, Fieldwood posted letters of credit in favor of Apache (Letters of Credit) and established trust accounts (Trust A and Trust B) of which Apache was a beneficiary and which were funded by two net profits interests (NPIs) depending on future oil prices. On February 14, 2018, Fieldwood filed for protection under Chapter 11 of the U.S. Bankruptcy Code. In connection with the 2018 bankruptcy, Fieldwood confirmed a plan under which Apache agreed, inter alia, to (i) accept bonds in exchange for certain of the Letters of Credit and (ii) amend the Trust A trust agreement and one of the NPIs to consolidate the trusts into a single Trust (Trust A) funded by both remaining NPIs. Currently, Apache holds two bonds (Bonds) and five Letters of Credit backed by investment-grade counterparties to secure Fieldwood's asset retirement obligations on the Legacy GOM Assets as and when Apache is required to perform or pay for decommissioning any Legacy GOM Asset over the remaining life of the Legacy GOM Assets.

On August 3, 2020, Fieldwood again filed for protection under Chapter 11 of the U.S. Bankruptcy Code. On June 25, 2021, the United States Bankruptcy Court for the Southern District of Texas (Houston Division) entered an order confirming Fieldwood's bankruptcy plan. On August 27, 2021, Fieldwood's bankruptcy plan became effective. Pursuant to the plan, the Legacy GOM Assets were separated into a standalone company, which was subsequently merged into GOM Shelf. Under GOM Shelf's limited liability company agreement, the proceeds of production of the Legacy GOM Assets will be used to fund decommissioning of Legacy GOM Assets.

In September 2021, GOM Shelf notified the Bureau of Safety and Environmental Enforcement (BSEE) that it was unable to fund the decommissioning obligations that it is currently required to perform on certain of the Legacy GOM Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE to decommission certain of the Legacy GOM Assets included in GOM Shelf's notification to BSEE. Apache expects to receive such orders on the other Legacy GOM Assets included in GOM Shelf's notification letter. Further, Apache anticipates that GOM Shelf may send additional such notices to BSEE in the future and that it may receive additional orders from BSEE requiring it to decommission other Legacy GOM Assets.

If Apache incurs costs to decommission any Legacy GOM Asset and GOM Shelf does not reimburse Apache for such costs, then Apache will obtain reimbursement from Trust A, the Bonds, and the Letters of Credit until such funds and securities are fully utilized. In addition, after such sources have been exhausted, Apache has agreed to provide a standby loan to GOM Shelf of up to $400 million to perform decommissioning (Standby Loan Agreement), with such standby loan secured by a first and prior lien on the Legacy GOM Assets.

If the combination of GOM Shelf's net cash flow from its producing properties, the Trust A funds, the Bonds, and the remaining Letters of Credit are insufficient to fully fund decommissioning of any Legacy GOM Assets that Apache may be ordered by BSEE to perform, or if GOM Shelf's net cash flow from its remaining producing properties after the Trust A funds, Bonds, and Letters of Credit are exhausted is insufficient to repay any loans made by Apache under the Standby Loan Agreement, then Apache may be forced to effectively use its available cash to fund the deficit.

As of December 31, 2021, Apache estimates that its potential liability to fund decommissioning of Legacy GOM Assets it may be ordered to perform ranges from $1.2 billion to $1.4 billion on an undiscounted basis. Management does not believe any specific estimate within this range is a better estimate than any other. Accordingly, during 2021, the Company recorded a contingent liability of $1.2 billion, representing the estimated costs of decommissioning it may be required to perform on Legacy GOM Assets. Of the total liability recorded, $1.1 billion is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $100 million is reflected under "Other current liabilities" in the Company's consolidated balance sheet. The Company also recorded a $740 million asset, which represents the amount the Company expects to be reimbursed from the Trust A funds, the Bonds, and the Letters of Credit for decommissioning it may be required to perform on Legacy GOM Assets. Of the total asset recorded, $640 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $100 million is reflected under "Other current assets." A "Loss on previously sold Gulf of Mexico properties" in the amount of $446 million was recognized in the third quarter of 2021 to reflect the net impact to the Company's statement of consolidated operations. Changes in significant assumptions impacting Apache's estimated liability, including expected decommissioning rig spread rates, lift boat rates, and planned abandonment logistics could result in a liability in excess of the amount accrued. In addition, significant changes in the market price of oil, gas, and NGLs could further impact Apache's estimate of its contingent liability to decommission Legacy GOM Assets.

Insurance Program

The Company maintains insurance policies that include coverage for physical damage to its assets, general liabilities, workers' compensation, employers' liability, sudden and accidental pollution, and other risks. The Company's insurance coverage is subject to deductibles or retentions that it must satisfy prior to recovering on insurance. Additionally, the Company's insurance is subject to policy exclusions and limitations. There is no assurance that insurance will adequately protect the Company against liability from all potential consequences and damages. Further, the Company does not have coverage in place for a variety of other risks including Gulf of Mexico named windstorm and business interruption. Service agreements, including drilling contracts, generally indemnify the Company for injuries and death of the service provider's employees as well as subcontractors hired by the service provider.

The Company purchases multi-year political risk insurance from The Islamic Corporation for the Insurance of Investment and Export Credit Trade (ICIEC, an agency of the Islamic Development Bank) and highly-rated insurers covering a portion of its investments in Egypt for losses arising from confiscation, nationalization, and expropriation risks. In the aggregate, these insurance policies provide up to $750 million of coverage, subject to policy terms and conditions and a retention of approximately $500 million.

The Company also has an insurance policy with U.S. International Development Finance Corporation (DFC), which, subject to policy terms and conditions, provides up to $150 million of coverage through 2024 for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed the Company on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent the Company from exporting its share of production. The Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, provides $60 million in reinsurance to DFC.

Future insurance coverage for the Company's industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable or unavailable on terms economically acceptable.

Critical Accounting Estimates

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

Reserves Estimates

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

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

Despite the inherent imprecision in these engineering estimates, the Company's reserves are used throughout its financial statements. For example, since the Company uses the units-of-production method to amortize its oil and gas properties, the quantity of reserves could significantly impact DD&A expense. A material adverse change in the estimated volumes of reserves could result in property impairments. Finally, these reserves are the basis for the Company's supplemental oil and gas disclosures. For more information regarding the Company's supplemental oil and gas disclosures, refer to Note 18—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Reserves are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous twelve months, held flat for the life of the production, except where prices are defined by contractual arrangements. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation.

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

Oil and Gas Exploration Costs

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

Offshore Decommissioning Contingency

The Company has potential exposure to future obligations related to divested properties. For information regarding a potential obligation to decommission sold properties estimated and recorded in the third quarter of 2021, please refer to "Potential Obligation to Decommission Sold Properties" above and in Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part IV, Item 5 of this Annual Report on Form 10-K. Changes in significant assumptions impacting the Company's estimated liability, including expected decommissioning rig spread rates, lift boat rates, and planned abandonment logistics could result in a liability in excess of the amount accrued. In addition, significant changes in the market price of oil, gas, and NGLs could further impact the Company's estimate of its contingent liability to decommission Legacy GOM Assets.

Impairment of Equity Method Interests

Equity method interests are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income.

Altus recorded an impairment charge on its equity method interest in EPIC in the fourth quarter of 2021. The fair value of the impaired interest was determined using the income approach. The income approach considered estimates of future throughput volumes, tariff rates, and costs. These assumptions were applied to develop future cash flow projections that were then discounted to estimated fair value, using a discount rate believed to be consistent with that which would be applied by market participants. The Company has classified this nonrecurring fair value measurement as Level 3 in the fair value hierarchy. Refer to Note 6—Equity Method Interests, within Part IV, Item 15 of this Annual Report on Form 10-K for further details of Altus' equity method interests. Negative revisions in future estimates of throughput volumes, revenue assumptions or costs related to the Altus' equity method interests could lead to further impairments of such interests in future periods.

Long-Lived Asset Impairments

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

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

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

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

Over the past several years, the Company has experienced substantial volatility in commodity prices, which impacted its future development plans and operating cash flows. As such, material impairments of certain proved oil and gas properties and gathering, processing, and transmission facilities were recorded in 2020 and 2019. For discussion of these impairments, see "Fair Value Measurements" of Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Asset Retirement Obligation (ARO)

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

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Income Taxes

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

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

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

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

Commodity Price Risk

The Company's revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices the Company receives for its crude oil, natural gas, and NGLs, which have historically been very volatile because of unpredictable events such as economic growth or retraction, weather, political climate, and global supply and demand. These factors have only been heightened as the implications of the COVID-19 pandemic became more apparent. The Company continually monitors its market risk exposure, including the impact and developments related to the COVID-19 pandemic, which introduced significant volatility in the financial markets beginning in early 2020.

The Company's average crude oil realizations increased 74 percent to $68.97 per barrel in 2021 from $39.60 per barrel in 2020. The Company's average natural gas price realizations increased 118 percent to $3.99 per Mcf in 2021 from $1.83 per Mcf in 2020. The Company's average NGL realizations increased 141 percent to $28.48 per barrel in 2021 from $11.84 per barrel in 2020. Based on average daily production for 2021, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $66 million, a $0.10 per Mcf change in the weighted average realized price of natural gas would have increased or decreased revenues for the year by approximately $30 million, and a $1.00 per barrel change in the weighted average realized NGL price would have increased or decreased revenues for the year by approximately $25 million.

The Company periodically enters into derivative positions on a portion of its projected crude oil and natural gas production through a variety of financial and physical arrangements intended to manage fluctuations in cash flows resulting from changes in commodity prices. Such derivative positions may include the use of futures contracts, swaps, and/or options. The Company does not hold or issue derivative instruments for trading purposes. As of December 31, 2021, the Company had open natural gas derivatives, not designated as cash flow hedges, in a liability position with a fair value of approximately $10 million. A 10 percent increase in basis differential of the hedges would increase the liability by approximately $30 million, while a 10 percent decrease in basis differential of the hedges would move the derivatives to an asset position of approximately $21 million. These fair value changes assume volatility based on prevailing market parameters as of December 31, 2021. Refer to Note 4—Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report Form 10-K for notional volumes and terms with the Company's derivative contracts.

Interest Rate Risk

At December 31, 2021, Apache had $6.3 billion, net, in outstanding notes and debentures, all of which was fixed-rate debt, with a weighted average interest rate of 5.07 percent. Although near-term changes in interest rates may affect the fair value of fixed-rate debt, such changes do not expose the Company to the risk of earnings or cash flow loss associated with that debt. The Company is also exposed to interest rate risk related to its interest-bearing cash and cash equivalents balances and amounts outstanding under the Apache and Altus Midstream LP credit facilities. As of December 31, 2021, the Company had approximately $302 million in cash and cash equivalents, approximately 57 percent of which was invested in money market funds and short-term investments with major financial institutions. As of December 31, 2021, there were $542 million and $657 million of borrowings outstanding under the Apache Corporation and Altus Midstream LP revolving credit facilities, respectively. A change in the interest rate applicable to short-term investments and credit facility borrowings would have an immaterial impact on earnings and cash flows but could impact interest costs associated with future debt issuances or any future borrowings.

Foreign Currency Exchange Rate Risk

The Company's cash activities relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The Company's North Sea production is sold under U.S. dollar contracts, while the majority of costs incurred are paid in British pounds. The Company's Egypt production is primarily sold under U.S. dollar contracts, and the majority of costs incurred are denominated in U.S. dollars. Transactions denominated in British pounds are converted to U.S. dollar equivalents based on the average exchange rates during the period.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Foreign currency gains and losses are included as either a component of "Other" under "Revenues and Other" or, as is the case when the Company re-measures its foreign tax liabilities, as a component of the Company's provision for income tax expense on the statement of consolidated operations. A foreign currency net gain or loss of $3 million would result from a 10 percent weakening or strengthening, respectively, in the British pound as of December 31, 2021.

The Company is subject to increased foreign currency risk associated with the effects of the U.K.'s withdrawal from the European Union. The Company has periodically entered into foreign exchange contracts in order to minimize the impact of fluctuating exchange rates for the British pound on the Company's operating expenses. As of December 31, 2021, the Company had outstanding foreign exchange contracts with a total notional amount of £180 million that are used to reduce its exposure to fluctuating foreign exchange rates for the British pound. A 10 percent strengthening of the British pound against the U.S. dollar would result in a foreign currency net gain of $20 million, while a 10 percent weakening of the British pound against the U.S. dollar would result in a loss of $14 million as of December 31, 2021.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

The financial statements and supplementary financial information required to be filed under this Item 8 are presented on pages F-1 through F-66 in Part IV, Item 15 of this Annual Report on Form 10-K and are incorporated herein by reference.

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

The financial statements for the fiscal years ended December 31, 2021, 2020, and 2019, included in this Annual Report on Form 10-K, have been audited by Ernst & Young LLP, independent registered public accounting firm, as stated in their audit report appearing herein. There have been no changes in or disagreements with the accountants during the periods presented.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

John J. Christmann IV, the Company's Chief Executive Officer and President, in his capacity as principal executive officer, and Stephen J. Riney, the Company's Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of December 31, 2021, the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective, providing effective means to ensure that the information the Company is required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the Commission's rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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

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

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to the "Report of Management on Internal Control Over Financial Reporting," included on Page F-1 in Part IV, Item 15 of this Annual Report on Form 10-K.

The independent auditors attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to the "Report of Independent Registered Public Accounting Firm," included on Page F-3 through F-5 in Part IV, Item 15 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2021, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. *OTHER INFORMATION*

None.

ITEM 9C. *DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS*

Not applicable.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information set forth under the captions “Nominees for Election as Directors,” “Information About Our Executive Officers,” and “Securities Ownership and Principal Holders” in the proxy statement relating to the Company’s 2022 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 5610 of the Nasdaq, the Company is required to adopt a code of business conduct and ethics for its directors, officers, and employees. In February 2004, the board of directors of Apache, the Company’s predecessor registrant, adopted the Code of Business Conduct and Ethics (Code of Conduct) and the Company’s board of directors, as part of the Holding Company Reorganization, adopted and revised it in March 2021. The revised Code of Conduct also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access the Company’s Code of Conduct on the Governance page of the Company’s website at www.apacorp.com. Any shareholder who so requests may obtain a printed copy of the Code of Conduct by submitting a request to the Company’s corporate secretary at the address on the cover of this Annual Report on Form 10-K. Changes in and waivers to the Code of Conduct for the Company’s directors, chief executive officer and certain senior financial officers will be posted on the Company’s website within four business days and maintained for at least 12 months. Information on the Company’s website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

ITEM 11. *EXECUTIVE COMPENSATION*

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

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

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

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

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

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

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

PART IV

ITEM 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULES***

(a) Documents included in this report:

1. Financial Statements

2. Financial Statement Schedules

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

3. Exhibits

EXHIBIT NO.		DESCRIPTION
2.1	–	Agreement and Plan of Merger, dated as of March 1, 2021, by and among Apache Corporation, Registrant, and APA Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
3.1	–	Amended and Restated Certificate of Incorporation of Registrant, dated March 1, 2021 (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
3.2	–	Amended and Restated Bylaws of Registrant, dated September 14, 2021 (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed September 20, 2021, SEC File No. 001-40144).
4.1	–	Form of Certificate for Registrant's Common Stock (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
4.2	–	Description of Equity Securities of the Registrant (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
10.1	–	Assignment and Assumption Agreement, dated as of March 1, 2021, by and between Registrant and Apache Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.2	–	APA Corporation Income Continuance Plan, as amended and restated effective as of March 1, 2021 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.3	–	APA Corporation Executive Termination Policy, as amended and restated effective as of March 1, 2021 (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.4	–	APA Corporation 2016 Omnibus Compensation Plan, dated February 3, 2016, effective May 12, 2016 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Current Report on Form 8-K filed May 16, 2016, SEC File No. 001-4300).
†10.5	–	First Amendment to the Registrant's 2016 Omnibus Compensation Plan, dated July 29, 2019 (incorporated by reference to Exhibit 10.13 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.6	–	Second Amendment to the Registrant's 2016 Omnibus Compensation Plan, dated March 1, 2021 (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K12B filed on March 1, 2021, SEC File No. 001-40144).
†10.7	–	APA Corporation 2011 Omnibus Equity Compensation Plan, as amended and restated May 12, 2016 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, SEC File No. 001-4300).
†10.8	–	First Amendment to the Registrant's 2011 Omnibus Equity Compensation Plan, dated July 29, 2019 (incorporated by reference to Exhibit 10.15 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.9	–	Second Amendment to the Registrant's 2011 Omnibus Equity Compensation Plan, dated March 1, 2021 (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.10	–	APA Corporation 2007 Omnibus Equity Compensation Plan, as amended and restated May 4, 2011 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, SEC File No. 001-4300).
†10.11	–	First Amendment to the Registrant's 2007 Omnibus Equity Compensation Plan, dated March 1, 2021 (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.12	–	APA Corporation Deferred Delivery Plan, as amended and restated May 12, 2016 (incorporated by reference to Exhibit 10.3 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, SEC File No. 001-4300).
†10.13	–	APA Corporation Non-Employee Directors' Compensation Plan, as amended and restated July 13, 2017 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, SEC File No. 001-4300).
†10.14	–	APA Corporation Outside Directors' Retirement Plan, as amended and restated July 16, 2014, effective June 30, 2014 (incorporated by reference to Exhibit 10.5 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, SEC File No. 001-4300).
†10.15	–	APA Corporation Non-Employee Directors' Restricted Stock Units Program, as amended and restated May 14, 2015 (incorporated by reference to Exhibit 10.6 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, SEC File No. 001-4300).

EXHIBIT NO.		DESCRIPTION
†10.16	–	APA Corporation Non-Employee Directors' Restricted Stock Units Program, effective May 12, 2016, pursuant to the Registrant's 2016 Omnibus Compensation Plan (incorporated by reference to Exhibit 10.4 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, SEC File No. 001-4300).
†10.17	–	APA Corporation Outside Directors' Deferral Program, effective May 12, 2016, pursuant to the Registrant's 2016 Omnibus Compensation Plan (incorporated by reference to Exhibit 10.5 to Apache Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, SEC File No. 001-4300).
†10.18	–	Form of 2018 Restricted Stock Unit Award Agreement dated January 16, 2018 (2016 Omnibus Compensation Plan) (incorporated by reference to Exhibit 10.43 to Apache Corporation's Annual Report on Form 10-K for the year ended December 31, 2017, SEC File No. 001-04300).
†10.19	–	Form of 2018 Cash-Settled Restricted Stock Unit Award Agreement dated January 16, 2018 (2016 Omnibus Compensation Plan) (incorporated by reference to Exhibit 10.44 to Apache Corporation's Annual Report on Form 10-K for the year ended December 31, 2017, SEC File No. 001-04300).
†10.20	–	Form of 2018 Performance Share Grant Agreement (2016 Omnibus Compensation Plan), dated January 16, 2018 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Current Report on Form 8-K filed January 19, 2018, SEC File No. 001-04300).
†10.21	–	Form of 2018 Stock Option Grant Agreement (2016 Omnibus Compensation Plan), dated January 16, 2018 (incorporated by reference to Exhibit 10.2 to Apache Corporation's Current Report on Form 8-K filed January 19, 2018, SEC File No. 001-04300).
†10.22	–	Form of 2019 Performance Share Program (2016 Omnibus Compensation Plan), dated January 3, 2019 (incorporated by reference to Exhibit 10.1 to Apache Corporation's Current Report on Form 8-K filed January 7, 2019, SEC File No. 001-04300).
†10.23	–	Form of 2019 Cash-Based Restricted Stock Unit Grant Agreement (2016 Omnibus Compensation Plan), dated January 3, 2019 (incorporated by reference to Exhibit 10.2 to Apache Corporation's Current Report on Form 8-K filed January 7, 2019, SEC File No. 001-04300).
†10.24	–	Form of 2019 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2019 (incorporated by reference to Exhibit 10.47 to Apache Corporation's Annual Report on Form 10-K for the year ended December 31, 2018, SEC File No. 001-04300).
†10.25	–	Form of 2019 Cash-Based Restricted Stock Unit Grant Agreement (2016 Omnibus Compensation Plan), dated January 3, 2019 (incorporated by reference to Exhibit 10.48 to Apache Corporation's Annual Report on Form 10-K for the year ended December 31, 2018, SEC File No. 001-04300).
†10.26	–	Amendment of Performance Share Grant Agreement, dated July 29, 2019 (incorporated by reference to Exhibit 10.52 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.27	–	Amendment of Restricted Stock Unit Award Agreement, dated July 29, 2019 (incorporated by reference to Exhibit 10.53 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.28	–	Amendment of Stock Option Grant Agreement, dated July 29, 2019 (incorporated by reference to Exhibit 10.54 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.29	–	Form of 2020 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020 (incorporated by reference to Exhibit 10.55 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.30	–	Form of 2020 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020 (incorporated by reference to Exhibit 10.56 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.31	–	Form of 2020 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020 (incorporated by reference to Exhibit 10.57 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.32	–	Form of 2020 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020 (incorporated by reference to Exhibit 10.58 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
†10.33	–	Form of 2021 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021 (incorporated by reference to Exhibit 10.43 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2020, SEC File No. 001-04300).
†10.34	–	Form of 2021 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021 (incorporated by reference to Exhibit 10.44 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2020, SEC File No. 001-4300).

EXHIBIT NO.		DESCRIPTION
†10.35	–	Form of 2021 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021 (incorporated by reference to Exhibit 10.45 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2020, SEC File No. 001-4300).
†10.36	–	Form of 2021 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021 (incorporated by reference to Exhibit 10.46 to Apache Corporation's Annual Report on Form 10-K for year ended December 31, 2020, SEC File No. 001-04300).
†10.37	–	Amendment of Restricted Stock Unit Award Agreement, dated March 1, 2021 (incorporated by reference to Exhibit 10.7 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.38	–	Amendment of Performance Share Grant Agreement, dated March 1, 2021 (incorporated by reference to Exhibit 10.8 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.39	–	Amendment of Stock Option Grant Agreement, dated March 1, 2021 (incorporated by reference to Exhibit 10.9 to Registrant's Current Report on Form 8-K12B filed March 1, 2021, SEC File No. 001-40144).
†10.40	–	Form of 2022 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed January 7, 2022, SEC File No. 001-40144)
*†10.41	–	Form of 2022 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.
*†10.42	–	Form of 2022 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.
*†10.43	–	Form of 2022 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.
*21.1	–	Subsidiaries of Registrant.
*23.1	–	Consent of Ernst & Young LLP.
*23.2	–	Consent of Ryder Scott Company, L.P., Petroleum Consultants.
*24.1	–	Power of Attorney (included as a part of the signature pages to this report).
*31.1	–	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Executive Officer.
*31.2	–	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Financial Officer.
*32.1	–	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Executive Officer and Principal Financial Officer.
*99.1	–	Report of Ryder Scott Company, L.P., Petroleum Consultants.
*101.INS	–	Inline XBRL Instance Document (the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document).
*101.SCH	–	Inline XBRL Taxonomy Schema Document.
*101.CAL	–	Inline XBRL Calculation Linkbase Document.
*101.DEF	–	Inline XBRL Definition Linkbase Document.
*101.LAB	–	Inline XBRL Label Linkbase Document.
*101.PRE	–	Inline XBRL Presentation Linkbase Document.
*104	–	Cover Page Interactive Data File (the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document).

* Filed herewith.

† Management contracts or compensatory plans or arrangements required to be filed herewith pursuant to Item 15 hereof.

NOTE: Debt instruments of the Registrant defining the rights of long-term debt holders in principal amounts not exceeding 10 percent of the Registrant's consolidated assets have been omitted and will be provided to the Commission upon request.

ITEM 16. *FORM 10-K SUMMARY*

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

APA CORPORATION

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

Dated: February 22, 2022

POWER OF ATTORNEY

The officers and directors of APA Corporation, whose signatures appear below, hereby constitute and appoint John J. Christmann IV, Stephen J. Riney, and Rebecca A. Hoyt, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this report and each of the undersigned does hereby ratify and confirm all that said attorneys shall do or cause to be done by virtue thereof.

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

Name	Title	Date
/s/ John J. Christmann IV John J. Christmann IV	Director, Chief Executive Officer, and President (principal executive officer)	February 22, 2022
/s/ Stephen J. Riney Stephen J. Riney	Executive Vice President and Chief Financial Officer (principal financial officer)	February 22, 2022
/s/ Rebecca A. Hoyt Rebecca A. Hoyt	Senior Vice President, Chief Accounting Officer, and Controller (principal accounting officer)	February 22, 2022
/s/ Annell R. Bay Annell R. Bay	Director	February 22, 2022
/s/ Juliet S. Ellis Juliet S. Ellis	Director	February 22, 2022
/s/ Charles W. Hooper Charles W. Hooper	Director	February 22, 2022
/s/ Chansoo Joung Chansoo Joung	Director	February 22, 2022
/s/ John E. Lowe John E. Lowe	Independent, Non-Executive Chairman of the Board and Director	February 22, 2022
/s/ H. Lamar McKay H. Lamar McKay	Director	February 22, 2022
/s/ William C. Montgomery William C. Montgomery	Director	February 22, 2022
/s/ Amy H. Nelson Amy H. Nelson	Director	February 22, 2022
/s/ Daniel W. Rabun Daniel W. Rabun	Director	February 22, 2022
/s/ Peter A. Ragauss Peter A. Ragauss	Director	February 22, 2022

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2021. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework (2013).* Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2021.

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

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

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

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

Houston, Texas
February 22, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control Over Financial Reporting

We have audited APA Corporation and subsidiaries' internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, APA Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2021 and 2020, the related statements of consolidated operations, comprehensive income (loss), cash flows and changes in equity and noncontrolling interest for each of the three years in the period ended December 31, 2021, and the related notes and our report dated February 22, 2022 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of APA Corporation and subsidiaries (the Company) as of December 31, 2021 and 2020, the related statements of consolidated operations, comprehensive income (loss), cash flows and changes in equity and noncontrolling interest for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 22, 2022 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, depletion and amortization of property and equipment

Description of the Matter	At December 31, 2021, the carrying value of the Company’s property and equipment was $8,335 million, and depreciation, depletion and amortization (DD&A) expense was $1,360 million for the year then ended. As described in Note 1, the Company follows the successful efforts method of accounting for its oil and gas properties. DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company’s internal reservoir engineers. Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and natural gas liquids, 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. Significant judgment is required by the Company’s internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions, and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to audit the proved oil and gas reserve estimates prepared by the Company’s internal reservoir engineers for select properties as of December 31, 2021. Auditing the Company’s DD&A calculations is complex because of the use of the work of the internal reservoir engineers and the independent petroleum engineers and the evaluation of management’s determination of the inputs described above used by the engineers in estimating oil and gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company’s controls over its process to calculate DD&A, including management’s controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company’s internal reservoir engineers primarily responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates for select properties. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating oil and gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management’s development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company’s development plan and the availability of capital relative to the development plan. We also tested the mathematical accuracy of the DD&A calculation, including comparing the oil and gas reserve amounts used in the calculation to the Company’s reserve reports.

Accounting for asset retirement obligation for the North Sea segment

Description of the Matter	At December 31, 2021, the asset retirement obligation (ARO) balance totaled $2,130 million. As further described in Note 8, the Company's ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The estimation of the ARO related to the North Sea segment requires significant judgment given the magnitude of the expected retirement costs and higher estimation uncertainty related to the timing of settlements and settlement amounts. Auditing the Company's ARO for the North Sea segment is complex and highly judgmental because of the significant estimation required by management in determining the obligation. In particular, the estimate was sensitive to significant subjective assumptions such as retirement cost estimates and the estimated timing of settlements, which are both affected by expectations about future market and economic conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. We also tested management's controls over the completeness and accuracy of financial data used in the valuation. To test the ARO for the North Sea segment, our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates and timing of settlement assumptions. For example, we evaluated retirement cost estimates by comparing the Company's estimates to recent offshore activities and costs. Additionally, we compared assumptions for the timing of settlements to production forecasts. We also involved our internal specialists in testing the underlying retirement cost estimates.

Accounting for decommissioning contingency for sold Gulf of Mexico properties

Description of the Matter	At December 31, 2021, the decommissioning contingency for sold Gulf of Mexico properties (decommissioning contingency) balance totaled $1,186 million. As further described in Note 11, the Company's decommissioning contingency reflects the estimated undiscounted potential liability to fund decommissioning of the sold Gulf of Mexico properties. The estimation of the decommissioning contingency requires significant judgment given the magnitude and higher estimation uncertainty of the expected retirement costs. Auditing the Company's decommissioning contingency is complex and highly judgmental because of the significant estimation required by management in determining the decommissioning contingency. In particular, the estimate was sensitive to retirement cost and duration estimates, which are subjective assumptions affected by expectations about future market and economic conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's internal controls over its decommissioning contingency estimation process, including management's review of the significant assumptions that have a material effect on the determination of the contingency. We also tested management's controls over the completeness and accuracy of financial data used in the valuation. To test the decommissioning contingency, our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost and duration estimates. For example, we evaluated retirement cost estimates by comparing the Company's estimates to recent offshore activities and costs as well as current bids obtained from service providers. We also involved our internal specialists in testing the underlying retirement cost and duration estimates.

/s/ Ernst & Young LLP

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

Houston, Texas
February 22, 2022

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil, natural gas, and natural gas liquids production revenues	$ 6,498	$ 4,037	$ 6,315
Purchased oil and gas sales	1,487	398	176
Total revenues	7,985	4,435	6,491
Derivative instrument gains (losses), net	94	(223)	(35)
Gain on divestitures, net	67	32	43
Loss on previously sold Gulf of Mexico properties	(446)	—	—
Other, net	228	64	54
	7,928	4,308	6,553
OPERATING EXPENSES:			
Lease operating expenses	1,241	1,127	1,447
Gathering, processing, and transmission	264	274	306
Purchased oil and gas costs	1,580	357	142
Taxes other than income	204	123	207
Exploration	155	274	805
General and administrative	376	290	406
Transaction, reorganization, and separation	22	54	50
Depreciation, depletion, and amortization	1,360	1,772	2,680
Asset retirement obligation accretion	113	109	107
Impairments	208	4,501	2,949
Financing costs, net	514	267	462
	6,037	9,148	9,561
NET INCOME (LOSS) BEFORE INCOME TAXES	1,891	(4,840)	(3,008)
Current income tax provision	652	176	660
Deferred income tax provision (benefit)	(74)	(112)	14
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	1,313	(4,904)	(3,682)
Net income (loss) attributable to noncontrolling interest - Egypt	174	(121)	167
Net income (loss) attributable to noncontrolling interest - Altus	4	1	(334)
Net income attributable to Altus Preferred Unit limited partners	162	76	38
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 973	$ (4,860)	$ (3,553)
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 2.60	$ (12.86)	$ (9.43)
Diluted	$ 2.59	$ (12.86)	$ (9.43)
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	374	378	377
Diluted	375	378	377

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

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

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	$ 1,313	$ (4,904)	$ (3,682)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Pension and postretirement benefit plan	7	(2)	13
Share of equity method interests other comprehensive income (loss)	1	—	(1)
COMPREHENSIVE INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	1,321	(4,906)	(3,670)
Comprehensive income (loss) attributable to noncontrolling interest - Egypt	174	(121)	167
Comprehensive income (loss) attributable to noncontrolling interest - Altus	4	1	(334)
Comprehensive income attributable to Altus Preferred Unit limited partners	162	76	38
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 981	$ (4,862)	$ (3,541)

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

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss) including noncontrolling interests	$ 1,313	$ (4,904)	$ (3,682)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized derivative instrument losses (gains), net	(69)	87	44
Gain on divestitures, net	(67)	(32)	(43)
Exploratory dry hole expense and unproved leasehold impairments	97	211	676
Depreciation, depletion, and amortization	1,360	1,772	2,680
Asset retirement obligation accretion	113	109	107
Impairments	208	4,501	2,949
Provision for (benefit from) deferred income taxes	(74)	(112)	14
Loss (gain) from extinguishment of debt	104	(160)	75
Loss on previously sold Gulf of Mexico properties	446	—	—
Other	28	102	50
Changes in operating assets and liabilities:			
Receivables	(386)	149	133
Inventories	(9)	19	(41)
Drilling advances and other current assets	71	(29)	30
Deferred charges and other long-term assets	(42)	(13)	—
Accounts payable	245	(167)	(5)
Accrued expenses	127	(163)	(84)
Deferred credits and noncurrent liabilities	31	18	(36)
NET CASH PROVIDED BY OPERATING ACTIVITIES	3,496	1,388	2,867
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(1,101)	(1,270)	(2,594)
Additions to Altus gathering, processing, and transmission (GPT) facilities	(3)	(28)	(327)
Leasehold and property acquisitions	(9)	(4)	(40)
Contributions to Altus equity method interests	(28)	(327)	(501)
Acquisition of Altus equity method interests	—	—	(671)
Proceeds from asset divestitures	256	166	718
Other	52	(3)	(31)
NET CASH USED IN INVESTING ACTIVITIES	(833)	(1,466)	(3,446)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from Apache credit facility, net	392	150	—
Proceeds from Altus credit facility	33	228	396
Fixed rate debt borrowings	—	1,238	989
Payments on fixed-rate debt	(1,795)	(1,243)	(1,150)
Distributions to noncontrolling interest - Egypt	(279)	(91)	(305)
Distributions to Altus Preferred Unit limited partners	(46)	(23)	—
Redeemable noncontrolling interest - Altus Preferred Unit limited partners	—	—	611
Dividends paid	(52)	(123)	(376)
Treasury stock activity, net	(847)	1	2
Other	(29)	(44)	(55)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(2,623)	93	112
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	40	15	(467)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	262	247	714
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 302	$ 262	$ 247
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 442	$ 419	$ 394
Income taxes paid, net of refunds	$ 633	$ 212	$ 649

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

APA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31, 2021	December 31, 2020
	(In millions, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents ($132 and $24 related to Altus VIE)	$ 302	$ 262
Receivables, net of allowance of $109 and $95	1,394	908
Other current assets (Note 5) ($9 and $5 related to Altus VIE)	684	676
	2,380	1,846
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of successful efforts accounting:	40,749	41,819
Gathering, processing, and transmission facilities ($209 and $206 related to Altus VIE)	673	670
Other ($3 and $3 related to Altus VIE)	1,126	1,140
Less: Accumulated depreciation, depletion, and amortization ($25 and $13 related to Altus VIE)	(34,213)	(34,810)
	8,335	8,819
OTHER ASSETS:		
Equity method interests (Note 6) ($1,365 and $1,555 related to Altus VIE)	1,365	1,555
Decommissioning security for sold Gulf of Mexico properties (Note 11)	640	—
Deferred charges and other ($6 and $5 related to Altus VIE)	583	526
	$ 13,303	$ 12,746
LIABILITIES, NONCONTROLLING INTEREST, AND EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable ($12 and $6 related to Altus VIE)	$ 731	$ 444
Current debt	215	2
Other current liabilities (Note 7) ($15 and $4 related to Altus VIE)	1,171	862
	2,117	1,308
LONG-TERM DEBT (Note 9) ($657 and $624 related to Altus VIE)	7,295	8,770
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	148	215
Asset retirement obligation ($68 and $64 related to Altus VIE)	2,089	1,888
Decommissioning contingency for sold Gulf of Mexico properties (Note 11)	1,086	—
Other ($67 and $144 related to Altus VIE)	573	602
	3,896	2,705
REDEEMABLE NONCONTROLLING INTEREST - ALTUS PREFERRED UNIT LIMITED PARTNERS (Note 13)	712	608
EQUITY (DEFICIT):		
Common stock, $0.625 par, 860,000,000 shares authorized, 419,078,606 and 418,429,375 shares issued, respectively	262	262
Paid-in capital	11,645	11,735
Accumulated deficit	(9,488)	(10,461)
Treasury stock, at cost, 72,147,841 and 40,946,745 shares, respectively	(4,036)	(3,189)
Accumulated other comprehensive income	22	14
APA SHAREHOLDERS' DEFICIT	(1,595)	(1,639)
Noncontrolling interest - Egypt	820	925
Noncontrolling interest - Altus	58	69
TOTAL DEFICIT	(717)	(645)
	$ 13,303	$ 12,746

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

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CHANGES IN EQUITY (DEFICIT) AND NONCONTROLLING INTEREST

	Redeemable Noncontrolling Interest - Altus Preferred Unit Limited Partners	Common Stock	Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	APA SHAREHOLDERS' EQUITY (DEFICIT)	Noncontrolling Interests	TOTAL EQUITY (DEFICIT)
				(In millions)					
BALANCE AT DECEMBER 31, 2018	$ —	$ 260	$ 12,106	$ (2,048)	$ (3,192)	$ 4	$ 7,130	$ 1,682	$ 8,812
Net loss attributable to common stock	—	—	—	(3,553)	—	—	(3,553)	—	(3,553)
Net income attributable to noncontrolling interest - Egypt	—	—	—	—	—	—	—	167	167
Net loss attributable to noncontrolling interest - Altus	—	—	—	—	—	—	—	(334)	(334)
Issuance of Altus Preferred Units	517	—	—	—	—	—	—	—	—
Net income attributable to Altus Preferred Unit limited partners	38	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest - Egypt	—	—	—	—	—	—	—	(305)	(305)
Common dividends ($1.00 per share)	—	—	(376)	—	—	—	(376)	—	(376)
Common stock activity, net	—	1	(22)	—	—	—	(21)	—	(21)
Compensation expense	—	—	61	—	—	—	61	—	61
Other	—	—	—	—	2	12	14	—	14
BALANCE AT DECEMBER 31, 2019	$ 555	$ 261	$ 11,769	$ (5,601)	$ (3,190)	$ 16	$ 3,255	$ 1,210	$ 4,465
Net loss attributable to common stock	—	—	—	(4,860)	—	—	(4,860)	—	(4,860)
Net loss attributable to noncontrolling interest - Egypt	—	—	—	—	—	—	—	(121)	(121)
Net income attributable to noncontrolling interest - Altus	—	—	—	—	—	—	—	1	1
Distributions paid to Altus Preferred Unit limited partners	(23)	—	—	—	—	—	—	—	—
Net income attributable to Altus Preferred Unit limited partners	76	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest - Egypt	—	—	—	—	—	—	—	(91)	(91)
Common dividends ($0.10 per share)	—	—	(38)	—	—	—	(38)	—	(38)
Common stock activity, net	—	1	(18)	—	—	—	(17)	—	(17)
Compensation expense	—	—	23	—	—	—	23	—	23
Other	—	—	(1)	—	1	(2)	(2)	(5)	(7)
BALANCE AT DECEMBER 31, 2020	$ 608	$ 262	$ 11,735	$ (10,461)	$ (3,189)	$ 14	$ (1,639)	$ 994	$ (645)
Net income attributable to common stock	—	—	—	973	—	—	973	—	973
Net income attributable to noncontrolling interest - Egypt	—	—	—	—	—	—	—	174	174
Net income attributable to noncontrolling interest - Altus	—	—	—	—	—	—	—	4	4
Net income attributable to Altus Preferred Unit limited partners	162	—	—	—	—	—	—	—	—
Distributions payable to Altus Preferred Unit limited partners	(12)	—	—	—	—	—	—	—	—
Distributions paid to Altus Preferred Unit limited partners	(46)	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest - Egypt	—	—	—	—	—	—	—	(279)	(279)
Common dividends ($0.2375 per share)	—	—	(87)	—	—	—	(87)	—	(87)
Common stock activity, net	—	—	(6)	—	—	—	(6)	—	(6)
Treasury stock activity, net	—	—	—	—	(847)	—	(847)	—	(847)
Compensation expense	—	—	21	—	—	—	21	—	21
Other	—	—	(18)	—	—	8	(10)	(15)	(25)
BALANCE AT DECEMBER 31, 2021	$ 712	$ 262	$ 11,645	$ (9,488)	$ (4,036)	$ 22	$ (1,595)	$ 878	$ (717)

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

Nature of Operations

APA Corporation (APA or the Company) is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. The Company's upstream business has exploration and production operations in three geographic areas: the United States (U.S.), Egypt, and offshore the U.K. in the North Sea (North Sea). APA also has active exploration and appraisal operations ongoing in Suriname, as well as interests in other international locations that may, over time, result in reportable discoveries and development opportunities. The Company's midstream business (Altus Midstream) is operated by Altus Midstream Company (Nasdaq: ALTM) through its subsidiary Altus Midstream LP (collectively, Altus). Altus owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas.

On January 4, 2021, Apache Corporation announced plans to implement a holding company reorganization (the Holding Company Reorganization), which was thereafter completed on March 1, 2021. In connection with the Holding Company Reorganization, Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares were automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by APA and its subsidiaries reflect industry practices and conform to accounting principles generally accepted in the U.S. (GAAP). The Company's financial statements for prior periods include reclassifications that were made to conform to the current-year presentation. Significant accounting policies are discussed below.

Principles of Consolidation

The implementation of the Holding Company Reorganization was accounted for as a merger under common control. APA recognized the assets and liabilities of Apache at carryover basis. The consolidated financial statements of APA present comparative information for prior years on a combined basis, as if both APA and Apache were under common control for all periods presented.

The accompanying consolidated financial statements include the accounts of APA and its subsidiaries after elimination of intercompany balances and transactions. The Company's undivided interests in oil and gas exploration and production ventures and partnerships are proportionately consolidated.

The Company consolidates all other investments in which, either through direct or indirect ownership, it has more than a 50 percent voting interest or controls the financial and operating decisions. ALTM is consolidated and qualifies as a variable interest entity (VIE) under GAAP. Additionally, in November of 2021, the Company determined that a limited partnership and APA subsidiary, which has control over APA's Egyptian operations, qualifies as a VIE under GAAP. Apache consolidates the activities of ALTM and APA's Egyptian operations because it has concluded that wholly owned subsidiaries have a controlling financial interest in ALTM and APA's Egyptian operations, respectively, and were determined to be the primary beneficiaries of the VIEs. Additionally, the assets of ALTM may only be used to settle obligations of ALTM. There is no recourse to the Company for ALTM's liabilities.

Noncontrolling interests represent third-party ownership in the net assets of a consolidated subsidiary of APA and are reflected separately in the Company's financial statements. Sinopec International Petroleum Exploration and Production Corporation (Sinopec) owns a one-third minority participation in the Company's Egypt oil and gas business as a noncontrolling interest, which is reflected as a separate component of equity in the Company's consolidated balance sheet. Additionally, third-party investors own a minority interest of approximately 21 percent of Altus Midstream Company (ALTM), which is reflected as a separate noncontrolling interest component of equity in the Company's consolidated balance sheet. APA regularly reassesses whether changes in the facts and circumstances regarding the Company's involvement with a VIE could cause a change in its conclusions related to consolidation. Changes in consolidation status, if any, are applied prospectively.

On June 12, 2019, Altus Midstream LP issued and sold Series A Cumulative Redeemable Preferred Units (the Preferred Units) through a private offering that admitted additional limited partners with separate rights for the Preferred Unit holders. Refer to Note 13—Redeemable Noncontrolling Interest — Altus for further detail.

Investments in which the Company holds less than 50 percent of the voting interest are typically accounted for under the equity method of accounting. These investments are recorded separately as “Equity method interests” in the Company’s consolidated balance sheet. The Company’s proportionate share of the results of operations generated by the equity method interests are recorded as a component of “Other, net” under “Revenues and Other” in the Company’s statement of consolidated operations. Refer to Note 6—Equity Method Interests for further detail.

Use of Estimates

Preparation of financial statements in conformity with GAAP and disclosure of contingent assets and liabilities requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. The Company evaluates its estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of the Company’s financial statements and changes in these estimates are recorded when known.

Significant estimates with regard to these financial statements include the estimates of fair value for long-lived assets (refer to “Fair Value Measurements” and “Property and Equipment” sections in this Note 1 below), the fair value determination of acquired assets and liabilities (refer to Note 2—Acquisitions and Divestitures), the fair value of equity method interests (refer to “Equity Method Interests” within this Note 1 below and Note 6—Equity Method Interests), the assessment of asset retirement obligations (refer to Note 8—Asset Retirement Obligation), the estimate of income taxes (refer to Note 10—Income Taxes), the estimation of the contingent liability representing the Company’s potential obligation to decommission sold properties in the Gulf of Mexico (refer to Note 11—Commitments and Contingencies), and the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (refer to Note 18—Supplemental Oil and Gas Disclosures (Unaudited)).

Fair Value Measurements

Certain assets and liabilities are reported at fair value on a recurring basis in the Company’s consolidated balance sheet. Accounting Standards Codification (ASC) 820-10-35, “Fair Value Measurement” (ASC 820), provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models, and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

Recurring fair value measurements are presented in further detail in Note 4—Derivative Instruments and Hedging Activities, Note 9—Debt and Financing Costs, Note 12—Retirement and Deferred Compensation Plans, and Note 13—Redeemable Noncontrolling Interest - Altus.

The Company also uses fair value measurements on a nonrecurring basis when certain qualitative assessments of its assets indicate a potential impairment. The following table presents a summary of asset impairments recorded in connection with fair value assessments:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Oil and gas proved property	$ —	$ 4,319	$ 1,484
Gathering, processing, and transmission facilities	—	68	1,295
Equity method interests	160	—	—
Divested unproved properties and leasehold	—	—	149
Goodwill	—	87	—
Inventory and other	48	27	21
Total Impairments	$ 208	$ 4,501	$ 2,949

For the year ended December 31, 2021, the Company recorded asset impairments totaling $208 million. These charges include a $160 million impairment on the Company's equity method interest in the EPIC crude oil pipeline (EPIC) as part of Altus' review of the fair value of its assets in relation to the announced BCP Business Combination. Refer to "Equity Method Interests" within this Note 1 below and Note 2—Acquisitions and Divestitures for further detail on the BCP Business Combination. The Company also recorded other impairments during 2021 of approximately $26 million in connection with inventory valuations in Egypt and $22 million in connection with inventory valuations and expected equipment dispositions in the North Sea.

For the year ended December 31, 2020, the Company recorded asset impairments totaling $4.5 billion in connection with non-recurring fair value assessments. Given the crude oil price collapse on lower demand and economic activity resulting from the coronavirus disease 2019 (COVID-19) global pandemic and related governmental actions, the Company assessed its oil and gas property and gathering, processing, and transmission (GPT) facilities for impairment based on the net book value of its assets as of March 31, 2020. The Company recognized proved property impairments of $3.9 billion, $354 million, and $7 million in the U.S., Egypt, and North Sea, respectively, all of which were impaired to their estimated fair values as a result of lower forecasted commodity prices, changes to planned development activity, and increasing market uncertainty. Similarly, the Company recognized GPT facility impairments of $68 million in Egypt. These impairments are discussed in further detail below in "Property and Equipment - Oil and Gas Property" and "Property and Equipment - Gathering, Processing, and Transmission Facilities."

The Company also performed an interim impairment analysis of the goodwill related to its Egypt reporting unit. Reductions in estimated net present value of expected future cash flows from oil and gas properties resulted in implied fair values below the carrying values of the Company's Egypt reporting unit. As a result of these assessments, the Company recognized non-cash impairments of the entire amount of recorded goodwill in the Egypt reporting unit of $87 million in the first quarter of 2020.

During the remainder of 2020, the Company recorded additional proved property impairments totaling $20 million in Egypt, as well as $13 million for the early termination of drilling rig leases, $5 million for inventory revaluations, and $9 million of other asset impairments, all in the U.S.

During the fourth quarter of 2019, following a material reduction to planned investment in the Company's Alpine High development, the Company recorded impairments totaling $1.4 billion for its Alpine High proved properties and upstream infrastructure which were written down to their fair values. Altus separately assessed its long-lived infrastructure assets for impairment based on expected reductions to future throughput volumes from Alpine High. Altus subsequently recorded impairments totaling $1.3 billion on its GPT facilities. These impairments are discussed in further detail below in "Property and Equipment - Oil and Gas Property" and "Property and Equipment - Gathering, Processing, and Transmission Facilities."

Separate from the Company's Alpine High and Altus impairments, the Company entered into agreements to sell certain of its assets in the Western Anadarko Basin in Oklahoma and Texas. As a result of these agreements, a separate impairment analysis was performed for each of the assets within the disposal groups. The analyses were based on the agreed-upon proceeds less costs to sell for the transaction, a Level 1 fair value measurement. The carrying value of the net assets to be divested exceeded the fair value implied by the expected net proceeds, resulting in impairments in the second and fourth quarters of 2019 totaling $255 million, including $101 million on the Company's proved properties, $149 million on its unproved properties, and $5 million on other working capital. For more information regarding this transaction, refer to Note 2—Acquisitions and Divestitures.

Revenue Recognition

Upstream

The Company's upstream oil and gas segments primarily generate revenue from contracts with customers from the sale of its crude oil, natural gas, and natural gas liquids production volumes. In addition to APA-related production volumes, the Company also sells commodity volumes purchased from third-parties to fulfill sales obligations and commitments as the Company's production fluctuates with potential operational issues and changes to development plans. Under these short-term commodity sales contracts, the physical delivery of each unit of quantity represents a single, distinct performance obligation on behalf of the Company. Contract prices are determined based on market-indexed prices, adjusted for quality, transportation, and other market-reflective differentials. Revenue is measured by allocating an entirely variable market price to each performance obligation and recognized at a point in time when control is transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to: whether the purchaser can direct the use of the hydrocarbons, the transfer of significant risks and rewards, and the Company's right to payment. Control typically transfers to customers upon the physical delivery at specified locations within each contract and the transfer of title.

APA's Egypt operations are conducted pursuant to production-sharing contracts (PSCs). Under the terms of the Company's PSCs, the Company is the contractor partner (Contractor) with the Egyptian General Petroleum Corporation (EGPC) and 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 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 the Company's Egypt operations despite impacting the Company's production and reserves. Revenues related to Egypt's tax volumes are considered revenue from a non-customer.

On December 27, 2021, the Company announced the ratification of a modernized PSC with the Egyptian Ministry of Petroleum and the EGPC, having an effective date of April 1, 2021. The new PSC consolidates 98 percent of gross acreage and 90 percent of gross production into a single concession and refreshes the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool to provide improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all the Company's production covered under the new concession. The APA subsidiary that became the sole Contractor under the PSC is owned by an APA-operated joint venture owned two-thirds by APA and one-third by Sinopec.

Refer to Note 17—Business Segment Information for a disaggregation of revenue by product and reporting segment.

Altus Midstream

The Company's Altus Midstream segment is operated by ALTM, through its subsidiary, Altus Midstream LP. Altus generates revenue from contracts with customers from its gathering, compression, processing, and transmission services provided on the Company's natural gas and natural gas liquid production volumes. Under these long-term commercial service contracts, providing the related service represents a single, distinct performance obligation on behalf of Altus that is satisfied over time. In accordance with the terms of these agreements, Altus primarily receives a fixed fee for each contract year, subject to yearly fee escalation recalculations. Revenue is primarily measured using the output method and recognized in the amount to which Altus has the right to invoice, as performance completed to date corresponds directly with the value to its customers. For the periods presented, Altus Midstream segment revenues were primarily attributable to sales between Altus and APA, which are fully eliminated upon consolidation.

Payment Terms and Contract Balances

Payments under all contracts with customers are typically due and received within a short-term period of one year or less, after physical delivery of the product or service has been rendered. Receivables from contracts with customers, net of allowance for credit losses, totaled $956 million and $670 million as of December 31, 2021 and 2020, respectively.

In accordance with the provisions of ASC 606, “Revenue from Contracts with Customers,” variable market prices for each short-term commodity sale are allocated entirely to each performance obligation as the terms of payment relate specifically to the Company’s efforts to satisfy its obligations. As such, the Company has elected the practical expedients available under the standard to not disclose the aggregate transaction price allocated to unsatisfied, or partially unsatisfied, performance obligations as of the end of the reporting period.

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. As of December 31, 2021 and 2020, the Company had $302 million and $262 million, respectively, of cash and cash equivalents, of which approximately $132 million and $24 million, respectively, was held by Altus. The Company had no restricted cash as of December 31, 2021 and 2020.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are stated at amortized cost net of an allowance for credit losses. The Company routinely assesses the collectability of its financial assets measured at amortized cost. In June 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2016-13, “Financial Instruments-Credit Losses.” The standard changes the impairment model for trade receivables, held-to-maturity debt securities, net investments in leases, loans, and other financial assets measured at amortized cost. This ASU requires the use of a new forward-looking “expected loss” model compared to the previous “incurred loss” model, resulting in accelerated recognition of credit losses. The Company adopted this update in the first quarter of 2020. This ASU primarily applies to the Company’s accounts receivable balances, of which the majority are received within a short-term period of one year or less. The Company monitors the credit quality of its counterparties through review of collections, credit ratings, and other analyses. The Company develops its estimated allowance for credit losses primarily using an aging method and analyses of historical loss rates as well as consideration of current and future conditions that could impact its counterparties’ credit quality and liquidity. The adoption and implementation of this ASU did not have a material impact on the Company’s financial statements.

The following table presents changes to the Company’s allowance for credit loss:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Allowance for credit loss at beginning of year	$ 95	$ 88	$ 92
Additional provisions for the year	19	7	3
Uncollectible accounts written off, net of recoveries	(5)	—	(7)
Allowance for credit loss at end of year	$ 109	$ 95	$ 88

Inventories

Inventories consist principally of tubular goods and equipment and are stated at the lower of weighted-average cost or net realizable value. Oil produced but not sold, primarily in the North Sea, is also recorded to inventory and is stated at the lower of the cost to produce or net realizable value.

Property and Equipment

The carrying value of the Company’s property and equipment represents the cost incurred to acquire the property and equipment, including capitalized interest, net of any impairments. For business combinations, property and equipment cost is based on the fair values at the acquisition date.

Oil and Gas Property

The Company follows the successful efforts method of accounting for its oil and gas property. Under this method of accounting, exploration costs such as exploratory geological and geophysical costs, delay rentals, and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead, and similar activities are expensed as incurred. If an exploratory well provides evidence to justify potential development of reserves, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory well costs in light of ongoing exploration activities; in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are assessed for impairment at least annually and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment based on the Company’s current exploration plans. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis over the average lease term at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged to exploration expense, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration costs in the statement of consolidated operations.

Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized. Depreciation of the cost of proved oil and gas properties is calculated using the unit-of-production (UOP) method. The UOP calculation multiplies the percentage of estimated proved reserves produced each quarter by the carrying value of associated proved oil and gas properties. The reserve base used to calculate depreciation for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate the depreciation for capitalized well costs is the sum of proved developed reserves only. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are included in the depreciable cost.

Oil and gas properties are grouped for depreciation in accordance with ASC 932 “Extractive Activities—Oil and Gas.” The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

When circumstances indicate that the carrying value of proved oil and gas properties may not be recoverable, the Company compares unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on the Company’s estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally estimated using the income approach described in ASC 820. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments, a Level 3 fair value measurement.

The significant decline in crude oil and natural gas prices, as well as longer-term commodity price outlooks, related to reduced demand for oil and natural gas as a result of the COVID-19 pandemic and related governmental actions indicated possible impairment of the Company’s proved and unproved oil and gas properties in early 2020. In addition to estimating risk-adjusted reserves and future production volumes, estimated future commodity prices are the largest driver in variability of undiscounted pre-tax cash flows. Expected cash flows were estimated based on management’s views of published West Texas Intermediate (WTI), Brent, and Henry Hub forward pricing as of the balance sheet dates. Other significant assumptions and inputs used to calculate estimated future cash flows include estimates for future development activity, exploration plans and remaining lease terms. A 10 percent discount rate, based on a market-based weighted-average cost of capital estimate, was applied to the undiscounted cash flow estimate to value all of the Company’s asset groups that were subject to impairment charges in 2019.

The following table represents non-cash impairments charges of the carrying value of the Company's proved and unproved properties:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Proved properties:			
U.S.	$ —	$ 3,938	$ 1,484
Egypt	—	374	—
North Sea	—	7	—
Total proved properties	$ —	$ 4,319	$ 1,484
Unproved properties:			
U.S.	$ 22	$ 92	$ 760
Egypt	8	8	8
North Sea	1	1	—
Total unproved properties	$ 31	$ 101	$ 768

Proved properties impaired had aggregate fair values as of the most recent date of impairment of $1.9 billion and $628 million for 2020 and 2019, respectively.

Unproved leasehold impairments are typically recorded as a component of "Exploration" expense in the Company's statement of consolidated operations. However, in 2019, unproved impairments of $149 million were recorded as a component of "Impairments" in connection with an agreement to sell certain non-core leasehold properties in Oklahoma and Texas.

Gains and losses on divestitures of the Company's oil and gas properties are recognized in the statement of consolidated operations upon closing of the transaction. Refer to Note 2—Acquisitions and Divestitures for more detail.

Gathering, Processing, and Transmission Facilities

GPT facilities totaled $673 million and $670 million at December 31, 2021 and 2020, respectively, with accumulated depreciation for these assets totaling $386 million and $323 million for the respective periods. GPT facilities are depreciated on a straight-line basis over the estimated useful lives of the assets. The estimation of useful life takes into consideration anticipated production lives from the fields serviced by the GPT assets, whether APA-operated or third party-operated, as well as potential development plans by the Company for undeveloped acreage within or in close proximity to those fields.

The Company assesses the carrying amount of its GPT facilities whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the carrying amount of these facilities is more than the sum of the undiscounted cash flows, an impairment loss is recognized for the excess of the carrying value over its fair value.

The Company assessed its long-lived infrastructure assets for impairment as of March 31, 2020, and recorded an impairment of $68 million on its GPT facilities in Egypt during the first quarter of 2020. The fair values of the impaired assets, which were determined to be $46 million, were estimated using the income approach, which considers internal estimates based on future throughput volumes from applicable development concessions in Egypt and estimated costs to operate. These assumptions were applied based on throughput assumptions developed in relation to the oil and gas proved property impairment assessment, as discussed above, to develop future cash flow projections that were then discounted to estimated fair value, using a 10 percent discount rate, based on a market-based weighted-average cost of capital estimate. The Company has classified these non-recurring fair value measurements as Level 3 in the fair value hierarchy.

As discussed under "Fair Value Measurements" above, the Company decided to materially reduce its planned investment in the Alpine High play during its fourth-quarter 2019 capital planning review. Altus management subsequently assessed its long-lived infrastructure assets for impairment given the expected reduction to future throughput volumes and recorded impairments of $1.3 billion on its gathering, processing, and transmission assets. The fair values of the impaired assets were determined to be $203 million as of the time of the impairment and were estimated using the income approach. The income approach considered internal estimates of future throughput volumes, processing rates, and costs. These assumptions were applied to develop future cash flow projections that were then discounted to estimated fair value, using discount rates believed to be consistent with those applied by market participants. The Company has classified these non-recurring fair value measurements as Level 3 in the fair value hierarchy.

Other Property and Equipment

Other property and equipment includes computer software and equipment, buildings, vehicles, furniture and fixtures, land, and other equipment. These assets are depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 20 years. Other property and equipment totaled $1.1 billion at each of December 31, 2021 and 2020, with accumulated depreciation for these assets totaling $901 million and $864 million at December 31, 2021 and 2020, respectively.

Asset Retirement Costs and Obligations

The initial estimated asset retirement obligation related to property and equipment and subsequent revisions are recorded as a liability at fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of an asset's retirement. Asset retirement costs are depreciated using a systematic and rational method similar to that used for the associated property and equipment. Accretion expense on the liability is recognized over the estimated productive life of the related assets.

Capitalized Interest

For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties actively being explored, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity method affiliates that are undergoing the construction of assets that have not commenced principal operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation.

Goodwill

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. The Company currently carries no goodwill, but, in comparative periods, it was recorded in "Deferred charges and other" in the Company's consolidated balance sheet. The Company assessed the carrying amount of goodwill by testing for impairment annually and when impairment indicators arose. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The Company assessed each country as a reporting unit, with Egypt being the only reporting unit to have associated goodwill during the periods presented. The fair value of the reporting unit was determined and compared to the book value of the reporting unit. If the fair value of the reporting unit was less than the book value, including goodwill, then goodwill was written down to its implied fair value through a charge to expense.

The following presents the changes to goodwill for the years ended 2020 and 2019:

	Egypt	Total
	(In millions)	
Goodwill at December 31, 2018	$ 87	$ 87
Impairments	—	—
Goodwill at December 31, 2019	87	87
Impairments	(87)	(87)
Goodwill at December 31, 2020	$ —	$ —

Reductions in estimated net present value of expected future cash flows from oil and gas properties during 2020 resulted in implied fair values below the carrying values of the Company's Egypt reporting unit. As a result of this assessment, the Company recognized non-cash impairments of the entire amount of recorded goodwill in the Egypt reporting unit of $87 million in 2020. This goodwill impairment was recorded in "Impairments" in the Company's statement of consolidated operations.

Equity Method Interests

The Company follows the equity method of accounting when it does not exercise control over its equity interests, but can exercise significant influence over the operating and financial policies of the entity. Under this method, the equity interests are carried originally at acquisition cost, increased by the Company’s proportionate share of the equity interest’s net income and contributions made by the Company, and decreased by the Company’s proportionate share of the equity interest’s net losses and distributions received by the Company.

Equity method interests are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income. In the fourth quarter of 2021, Altus, as part of its review of the fair value of its assets in relation to the announced BCP Business Combination, determined the current fair value of its investment in EPIC was below carrying value. Altus subsequently determined that this loss in value to be other than temporary. As such, in the fourth quarter of 2021, Altus recorded an impairment charge of $160 million on its equity method interest in EPIC. The fair value of the impaired interest was determined using the income approach. The income approach considered estimates of future throughput volumes, tariff rates, and costs. These assumptions were applied to develop future cash flow projections that were then discounted to estimated fair value, using a discount rate believed to be consistent with that which would be applied by market participants. Altus has classified this nonrecurring fair value measurement as Level 3 in the fair value hierarchy. Refer to Note 6—Equity Method Interests for further details of the Company’s equity method interests.

Commitments and Contingencies

Accruals for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change. For more information regarding loss contingencies, refer to Note 11—Commitments and Contingencies.

Derivative Instruments and Hedging Activities

The Company periodically enters into derivative contracts to manage its exposure to commodity price, interest rate, and/or foreign exchange risk. These derivative contracts, which are generally placed with major financial institutions, may take the form of forward contracts, futures contracts, swaps, or options.

All derivative instruments, other than those that meet the normal purchases and sales exception, are recorded on the Company’s consolidated balance sheet as either an asset or liability measured at fair value. The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses from the change in fair value of derivative instruments are reported in current-period income as “Derivative instrument losses, net” under “Revenues and Other” in the statement of consolidated operations. Refer to Note 4—Derivative Instruments and Hedging Activities for further information.

Income Taxes

The Company records deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. The Company routinely assesses the ability to realize its deferred tax assets. If the Company concludes that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

Earnings Per Share

The Company’s basic earnings per share (EPS) amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS reflects potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock was fully vested. The Company uses the “if-converted method” to determine the potential dilutive effect of an assumed exchange of the outstanding Preferred Units of Altus Midstream LP for shares of ALTM’s common stock. The impact to net income (loss) attributable to common stock on an assumed conversion of the redeemable noncontrolling Preferred Units interest in Altus Midstream LP were anti-dilutive for the years ended December 31, 2021, 2020, and 2019.

Stock-Based Compensation

The Company grants various types of stock-based awards including stock options, restricted stock, cash-settled restricted stock units, and performance-based awards. Stock compensation equity awards granted are valued on the date of grant and are expensed over the required vesting service period. Cash-settled awards are recorded as a liability based on the Company's stock price and remeasured at the end of each reporting period over the vesting terms. The Company has elected to account for forfeitures as they occur rather than estimate expected forfeitures. The Company's stock-based compensation plans and related accounting policies are defined and described more fully in Note 14—Capital Stock.

Treasury Stock

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

Transaction, Reorganization, and Separation (TRS)

In recent years, the Company streamlined its portfolio through strategic divestitures and centralized certain operational activities in an effort to capture greater efficiencies and cost savings through shared services. In light of the continued streamlining of the Company's asset portfolio through divestitures and strategic transactions, in late 2019 management initiated a comprehensive redesign of the Company's organizational structure and operations. Efforts related to this organization were substantially completed during 2020. The Company incurred and paid a cumulative total of $79 million of reorganization costs through December 31, 2020. An additional $17 million of reorganization costs were incurred during the year ended December 31, 2021, primarily related to ongoing consulting and separation activities in the Company's international operations.

The Company recorded $22 million, $54 million, and $50 million of TRS costs in 2021, 2020, and 2019, respectively. TRS costs incurred in 2021 relate to $11 million for consulting costs associated with the reorganization, $6 million of separation costs associated with the reorganization, and $5 million for costs associated with the BCP Business Combination. TRS costs incurred in 2020 relate to $51 million of separation costs associated with the reorganization, $2 million for transaction consulting fees, and $1 million of office closure costs. TRS costs incurred in 2019 associated with the reorganization include $26 million for employee termination benefits and $2 million for consulting fees. The Company also incurred $15 million of expenses for employee termination benefits and office closures associated with other reorganization efforts and $7 million for consulting and legal fees on various transactions throughout 2019.

New Pronouncements Issued But Not Yet Adopted

In March 2020, the FASB issued ASU 2020-04, "Reference Rate Reform (Topic 848)," which provides optional expedients and exceptions for applying U.S. GAAP to contracts, hedging relationships, and other transactions affected by the discontinuation of the London Interbank Offered Rate (LIBOR) or by another reference rate expected to be discontinued. In January 2021, the FASB issued ASU 2021-01, which clarified the scope and application of the original guidance. The guidance was effective beginning March 12, 2020 and can be applied prospectively through December 31, 2022. The Company is evaluating whether to apply any of these expedients and, if elected, will adopt these standards when LIBOR is discontinued.

In August 2020, the FASB issued ASU 2020-06, "Debt-Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging-Contracts in Entity's Own Equity (Subtopic 815-40)" to improve financial reporting associated with accounting for convertible instruments and contracts in an entity's own equity. This update is effective for the Company beginning in the first quarter of 2022 using either the modified or fully retrospective method with a cumulative effect adjustment to the opening balance of retained earnings. The Company does not believe it will have a material impact on its financial statements.

2. ACQUISITIONS AND DIVESTITURES

2022 Activity

In February 2022, the Company entered into an agreement to sell certain non-core mineral rights in the Delaware Basin for cash consideration of approximately $805 million, subject to customary post-closing adjustments. The transaction is expected to close in late February 2022, subject to regulatory approvals.

2021 Activity

During the second quarter of 2021, the Company completed the sale of certain non-core assets in the Permian Basin with a net carrying value of $157 million for cash proceeds of $176 million and the assumption of asset retirement obligations of $44 million. The Company recognized a gain of approximately $63 million in connection with the sale. The transaction is subject to normal post-closing adjustments.

During 2021, the Company also completed the sale of other non-core assets and leasehold, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $80 million. The Company recognized a gain of approximately $4 million upon closing of these transactions.

During 2021, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $9 million.

On October 21, 2021, ALTM announced that it will combine with privately-owned BCP Raptor Holdco LP (BCP) in an all-stock transaction (the BCP Business Combination). BCP is the parent company of EagleClaw Midstream, which includes EagleClaw Midstream Ventures, the Caprock Midstream and Pinnacle Midstream businesses, and a 26.7 percent interest in the Permian Highway Pipeline.

As consideration for the transaction, ALTM will issue 50 million shares of Class C Common Stock (and its subsidiary, Altus Midstream LP, will issue a corresponding number of common units) to BCP's unitholders, which are principally funds affiliated with Blackstone and I Squared Capital. The transaction is expected to close during the first quarter of 2022, following completion of customary closing conditions.

2020 Activity

During 2020, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $4 million. Also during 2020, the Company completed the sale of certain non-core assets and leasehold, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $87 million, and recognized a gain of $13 million.

2019 Activity

U.S. Divestitures and Leasehold, Property, and Other Acquisitions

In the third quarter of 2019, the Company completed the sale of non-core assets in the Western Anadarko Basin of Oklahoma and Texas for aggregate cash proceeds of approximately $322 million and the assumption of asset retirement obligations of $49 million. These assets met the criteria to be classified as held for sale in the second quarter of 2019. Accordingly, the Company performed a fair value assessment of the assets and recorded impairments of $240 million to the carrying value of proved and unproved oil and gas properties, other fixed assets, and working capital. The transaction closed in the third quarter of 2019, and the Company recognized a $7 million loss in connection with the sale.

In the second quarter of 2019, the Company completed the sale of certain non-core assets in Oklahoma that had a net carrying value of $206 million for aggregate cash proceeds of approximately $223 million. The Company recognized a $17 million gain in connection with the sale.

During 2019, the Company also completed the sale of certain other non-core producing assets, GPT assets, and leasehold acreage, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $73 million. The Company recognized a net gain of approximately $33 million upon closing of these transactions.

During 2019, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $40 million.

Suriname Joint Venture Agreement

In December 2019, the Company entered into a joint venture agreement with TotalEnergies (formerly, Total S.A.) to explore and develop Block 58 offshore Suriname. Under the terms of the agreement, the Company and TotalEnergies each hold a 50 percent working interest in Block 58. Pursuant to the agreement, the Company operated the drilling of the first four wells, the Maka Central-1, Sapakara West-1, Kwaskwasi-1, and Keskesi East-1, and subsequently transferred operatorship of Block 58 to TotalEnergies on January 1, 2021. The Company continued to operate the Keskesi exploration well until completion of drilling operations during the first half of 2021.

In connection with the agreement, the Company received $100 million from TotalEnergies upon closing in the fourth quarter of 2019 and $79 million upon satisfying certain closing conditions in the first quarter of 2020 for reimbursement of 50 percent of all costs incurred on Block 58 as of December 31, 2019. All proceeds were applied against the carrying value of the Company's Suriname properties and associated inventory. The Company recognized a $19 million gain in the first quarter of 2020 associated with the transaction.

Key terms of the agreement provide for TotalEnergies to pay a proportionately larger share of appraisal and development costs, which would be recoverable through hydrocarbon participation. For the first $10 billion of gross capital expenditures, TotalEnergies pays 87.5 percent, and the Company pays 12.5 percent; for the next $5 billion in gross expenditures, TotalEnergies pays 75 percent and the Company pays 25 percent; and for all gross expenditures above $15 billion, TotalEnergies pays 62.5 percent and the Company pays 37.5 percent. The Company will also receive various other forms of consideration, including a $75 million cash payment upon achieving first oil production, and future contingent royalty payments from successful joint development projects.

3. CAPITALIZED EXPLORATORY WELL COSTS

The following summarizes the changes in capitalized exploratory well costs for the years ended December 31, 2021, 2020, and 2019. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Capitalized well costs at beginning of year	$ 197	$ 141	$ 159
Additions pending determination of proved reserves	174	226	286
Divestitures and other	—	(38)	(100)
Reclassifications to proved properties	(40)	(56)	(179)
Charged to exploration expense	(10)	(76)	(25)
Capitalized well costs at end of year	$ 321	$ 197	$ 141

The following provides an aging of capitalized exploratory well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling as of December 31:

	2021	2020	2019
		(In millions)	
Exploratory well costs capitalized for a period of one year or less	$ 198	$ 184	$ 108
Exploratory well costs capitalized for a period greater than one year	123	13	33
Capitalized well costs at end of year	$ 321	$ 197	$ 141
Number of projects with exploratory well costs capitalized for a period greater than one year	13	5	2

Projects with suspended exploratory well costs capitalized for a period greater than one year since the completion of drilling are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development. Management is actively pursuing efforts to assess whether reserves can be attributed to these projects. Suspended exploratory well costs capitalized for a period greater than one year since the completion of drilling were $123 million at December 31, 2021, with $90 million related to Suriname. Analysis of well results is ongoing as is additional exploration and appraisal activity. Exploration and appraisal well activity in the North Sea accounted for $24 million, where subsurface evaluation and project viability assessment is ongoing. The remaining projects pertain to onshore drilling activity in Egypt for which continued testing and evaluation is ongoing.

Suspended exploratory well costs capitalized for a period greater than one year since the completion of drilling at December 31, 2020 and 2019, relate to onshore projects in Egypt and the U. S. Drilling activity and testing has continued for several of these projects in Egypt throughout 2021, and are currently being evaluated for potential development. The costs related to the U.S. projects were charged to exploration expense based on management’s assessment and development efforts.

In December 2019, the Company entered into the joint venture agreement with TotalEnergies, pursuant to which the Company sold 50 percent of its ownership interest in Block 58 to TotalEnergies. Proceeds received from TotalEnergies upon closing were applied against the carrying value of its Suriname properties.

The following table summarizes aging by geographic area of those exploratory well costs that, as of December 31, 2021, have been capitalized for a period greater than one year, categorized by the year in which drilling was completed:

	Total	2020	2019	2018 and Prior
		(In millions)		
Suriname	$ 90	$ 90	$ —	$ —
Egypt	9	—	—	9
North Sea	24	24	—	—
	$ 123	$ 114	$ —	$ 9

4. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Objectives and Strategies

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its worldwide production, as well as transactions denominated in foreign currencies. The Company manages the variability in its cash flows by occasionally entering into derivative transactions on a portion of its crude oil and natural gas production and foreign currency transactions. The Company utilizes various types of derivative financial instruments, including forward contracts, futures contracts, swaps, and options, to manage fluctuations in cash flows resulting from changes in commodity prices or foreign currency values.

Counterparty Risk

The use of derivative instruments exposes the Company to credit loss in the event of nonperformance by the counterparty. To reduce the concentration of exposure to any individual counterparty, the Company utilizes a diversified group of investment-grade rated counterparties, primarily financial institutions, for its derivative transactions. As of December 31, 2021, the Company had derivative positions with 10 counterparties. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties’ creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments resulting from lower commodity prices or changes in currency exchange rates.

Derivative Instruments

Commodity Derivative Instruments

As of December 31, 2021, the Company had the following open natural gas financial basis swap contracts:

		Basis Swap Purchased		Basis Swap Sold	
Production Period	Settlement Index	MMBtu (in 000's)	Weighted Average Price Differential	MMBtu (in 000's)	Weighted Average Price Differential
January—December 2022	NYMEX Henry Hub/IF Waha	43,800	$(0.45)	—	—
January—December 2022	NYMEX Henry Hub/IF HSC	—	—	43,800	$(0.08)
January—December 2023	NYMEX Henry Hub/IF Waha	29,200	$(0.40)	—	—
January—December 2023	NYMEX Henry Hub/IF HSC	—	—	29,200	$0.02

Foreign Currency Derivative Instruments

The Company has open foreign currency costless collar contracts in GBP/USD for £15 million per month for the calendar year 2022 with a weighted average floor and ceiling price of $1.39 and $1.29, respectively.

Embedded Derivatives

Altus Preferred Units Embedded Derivative

During the second quarter of 2019, Altus Midstream LP issued and sold the Preferred Units. Certain redemption features embedded within the Preferred Units require bifurcation and measurement at fair value. For further discussion of this derivative, refer to "Fair Value Measurements" below and Note 13—Redeemable Noncontrolling Interest — Altus.

Pipeline Capacity Embedded Derivatives

During the fourth quarter of 2019 and first quarter of 2020, the Company entered into an agreement to assign a portion of its contracted capacity under an existing transportation agreement to a third party. Embedded in this agreement is an arrangement under which the Company has the potential to receive payments calculated based on pricing differentials between Houston Ship Channel and Waha during calendar years 2020 and 2021. This feature requires bifurcation and measurement of the change in market value for each period. Unrealized gains or losses in the fair value of this feature are recorded as "Derivative instrument gains (losses), net" under "Revenues and Other" in the statement of consolidated operations. Any proceeds received are deferred and reflected in income over the original tenure of the host contract.

Fair Value Measurements

The following table presents the Company’s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements Using					
	Quoted Price in Active Markets (Level 1)	Significant Other Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Netting[1]	Carrying Amount
			(In millions)			
December 31, 2021						
Liabilities:						
Commodity derivative instruments	$ —	$ 10	$ —	$ 10	$ —	$ 10
Pipeline capacity embedded derivatives	—	46	—	46	—	46
Preferred Units embedded derivative	—	—	57	57	—	57
December 31, 2020						
Assets:						
Commodity derivative instruments	$ —	$ 11	$ —	$ 11	$ —	$ 11
Liabilities:						
Pipeline capacity embedded derivatives	—	53	—	53	—	53
Preferred Units embedded derivative	—	—	139	139	—	139

(1) The derivative fair values are based on analysis of each contract on a gross basis, excluding the impact of netting agreements with counterparties.

The fair values of the Company’s derivative instruments and pipeline capacity embedded derivatives are not actively quoted in the open market. The Company primarily uses a market approach to estimate the fair values of these derivatives on a recurring basis, utilizing futures pricing for the underlying positions provided by a reputable third party, a Level 2 fair value measurement.

The fair value of the Preferred Units embedded derivative is calculated using an income approach, a Level 3 fair value measurement. The fair value determination is based on a range of factors, including expected future interest rates using the Black-Karasinski model, Altus’ imputed interest rate, interest rate volatility, the expected timing of periodic cash distributions, any anticipated early redemptions of the Preferred Units, the estimated timing for the potential exercise of the exchange option, and anticipated dividend yields of the Preferred Units. As of the December 31, 2021 valuation date, the Company used the forward B-rated Energy Bond Yield curve to develop the following key unobservable inputs used to value this embedded derivative:

	Quantitative Information About Level 3 Fair Value Measurements			
	Fair Value at December 31, 2021	Valuation Technique	Significant Unobservable Inputs	Range/Value
	(In millions)			
Preferred Units embedded derivative	$ 57	Option Model	Altus’ Imputed Interest Rate	5.54-11.21%
			Interest Rate Volatility	40.08%

In addition, no early redemptions of the Preferred Units were assumed for the December 31, 2020 valuation. As a result of the announced BCP Business Combination and associated publicly filed information, the December 31, 2021 valuation assumed 250,000 Preferred Units would be redeemed before the Preferred Unit holders had the right to exercise their exchange option. This early redemption assumption significantly reduced the value of the derivative liability year over year.

A one percent increase in the imputed interest rate assumption would significantly increase the value of the embedded derivative as of December 31, 2021, while a one percent decrease would lead to a similar decrease in value as of December 31, 2021. The assumed expected timing until exercise of the exchange option at December 31, 2021 was 4.45 years.

Derivative Activity Recorded in the Consolidated Balance Sheet

All derivative instruments are reflected as either assets or liabilities at fair value in the consolidated balance sheet. These fair values are recorded by netting asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. The carrying value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	For the Year Ended December 31,	
	2021	2020
	(In millions)	
Current Assets: Other current assets	$ —	$ 6
Other Assets: Deferred charges and other	—	5
Total derivative assets	$ —	$ 11
Current Liabilities: Other current liabilities	$ 4	$ —
Deferred Credits and Other Noncurrent Liabilities: Other	109	192
Total derivative liabilities	$ 113	$ 192

Derivative Activity Recorded in the Statement of Consolidated Operations

The following table summarizes the effect of derivative instruments on the Company's statement of consolidated operations:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Realized:			
Commodity derivative instruments	$ 25	$ (135)	$ 27
Foreign currency derivative instruments	—	(1)	—
Treasury-lock	—	—	(18)
Realized gain (loss), net	25	(136)	9
Unrealized:			
Commodity derivative instruments	(20)	11	(44)
Pipeline capacity embedded derivatives	7	(61)	8
Foreign currency derivative instruments	—	(1)	1
Preferred Units embedded derivative	82	(36)	(9)
Unrealized gain (loss), net	69	(87)	(44)
Derivative instrument gains (losses), net	$ 94	$ (223)	$ (35)

Derivative instrument gains and losses are recorded in "Derivative instrument gains (losses), net" under "Revenues and Other" in the Company's statement of consolidated operations. Unrealized gains (losses) for derivative activity recorded in the statement of consolidated operations are reflected in the statement of consolidated cash flows separately as "Unrealized derivative instrument losses (gains), net" in "Adjustments to reconcile net income (loss) to net cash provided by operating activities."

The Company seeks to maintain a balance between "first of month" and "gas daily pricing" for its U.S. natural gas portfolio and sales activities in a given month as part of its ordinary course of business. This is typically implemented through a combination of physical and financial contracts that settle monthly.

5. OTHER CURRENT ASSETS

The following table provides detail of the Company's other current assets as of December 31:

	2021	2020
	(In millions)	
Inventories	$ 473	$ 492
Drilling advances	55	113
Prepaid assets and other	56	71
Current decommissioning security for sold Gulf of Mexico assets	100	—
Total Other current assets	$ 684	$ 676

6. EQUITY METHOD INTERESTS

As of December 31, 2021 and 2020, the Company, through its ownership of Altus, has the following equity method interests in four Permian Basin long-haul pipeline entities, which are accounted for under the equity method of accounting. For each of the equity method interests, Altus has the ability to exercise significant influence based on certain governance provisions and its participation in activities and decisions that impact the management and economic performance of the equity method interests.

	Interest	2021	2020
		(In millions)	
Gulf Coast Express Pipeline LLC	16.0 %	$ 274	$ 284
EPIC Crude Holdings, LP	15.0 %	—	176
Permian Highway Pipeline LLC	26.7 %	630	615
Shin Oak Pipeline (Breviloba, LLC)	33.0 %	461	480
Total Altus equity method interests		$ 1,365	$ 1,555

As of December 31, 2021 and 2020, unamortized basis differences included in the equity method interest balances were $34 million and $38 million, respectively. These amounts represent differences in Altus' initial costs paid to acquire the equity method interests and its initial underlying equity in the respective entities, as well as capitalized interest related to Permian Highway Pipeline (PHP) construction costs. Unamortized basis differences are amortized into equity income (loss) over the useful lives of the underlying pipeline assets when they are placed into service.

The following table presents the activity in Altus' equity method interests for the years ended December 31, 2021 and 2020:

	Gulf Coast Express Pipeline LLC	EPIC Crude Holdings, LP	Permian Highway Pipeline LLC	Breviloba, LLC	Total
			(In millions)		
Balance at December 31, 2019	$ 291	$ 163	$ 311	$ 493	$ 1,258
Capital contributions	2	29	296	—	327
Distributions	(51)	—	—	(46)	(97)
Capitalized interest[1]	—	—	8	—	8
Equity income (loss), net	42	(16)	—	33	59
Balance at December 31, 2020	284	176	615	480	1,555
Capital contributions	—	2	26	—	28
Distributions	(50)	—	(74)	(49)	(173)
Equity income (loss), net	40	(19)	63	30	114
Accumulated other comprehensive loss	—	1	—	—	1
Impairment[2]	—	(160)	—	—	(160)
Balance at December 31, 2021	$ 274	$ —	$ 630	$ 461	$ 1,365

(1) Altus' proportionate share of the PHP construction costs is funded with Altus' revolving credit facility. Accordingly, Altus capitalized $8 million of related interest expense during 2020, which is included in the basis of the PHP equity interest.
(2) The Company impaired its investment in EPIC in the fourth quarter of 2021. Refer to Note 1—Summary of Significant Accounting Policies for further details on this impairment charge.

Summarized Combined Financial Information

The following presents summarized information of combined statement of operations for Altus' equity method interests (on a 100 percent basis):

	For the Year Ended December 31,		
	2021	2020	2019(1)
		(In millions)	
Operating revenues	$ 1,082	$ 707	$ 302
Operating income	548	331	121
Net income	468	256	120
Other comprehensive income (loss)	4	3	(8)

(1) Although Altus' interests in EPIC Crude Holdings, LP, Permian Highway Pipeline LLC, and Breviloba, LLC were acquired in March, May, and July 2019, respectively, the combined financial results are presented for the full year ended December 31, 2019 for comparability.

The following presents summarized combined balance sheet information for Altus' equity method interests (on a 100 percent basis) as of December 31:

	2021	2020
	(In millions)	
Current assets	$ 280	$ 260
Noncurrent assets	7,445	7,678
Total assets	$ 7,725	$ 7,938
Current liabilities	$ 153	$ 206
Noncurrent liabilities	1,193	1,191
Equity	6,379	6,541
Total liabilities and equity	$ 7,725	$ 7,938

7. OTHER CURRENT LIABILITIES

The following table provides detail of the Company's other current liabilities as of December 31:

	2021	2020
	(In millions)	
Accrued operating expenses	$ 129	$ 91
Accrued exploration and development	207	167
Accrued compensation and benefits	292	170
Accrued interest	107	140
Accrued income taxes	28	25
Current asset retirement obligation	41	56
Current operating lease liability	99	116
Current decommissioning contingency for sold Gulf of Mexico properties	100	—
Other	168	97
Total Other current liabilities	$ 1,171	$ 862

8. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company's asset retirement obligation (ARO) liability:

	For the Year Ended December 31,	
	2021	2020
	(In millions)	
Asset retirement obligation at beginning of the year	$ 1,944	$ 1,858
Liabilities incurred	3	10
Liabilities divested	(44)	(26)
Liabilities settled	(32)	(30)
Accretion expense	113	109
Revisions in estimated liabilities	146	23
Asset retirement obligation at end of the year	2,130	1,944
Less current portion	(41)	(56)
Asset retirement obligation, long-term	$ 2,089	$ 1,888

The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property or other long-lived asset balance.

During 2021 and 2020, the Company recorded $3 million and $10 million, respectively, in abandonment liabilities resulting from the Company's exploration and development capital program. Liabilities settled primarily relate to individual properties, platforms, and facilities plugged and abandoned during the period. During 2021, approximately $146 million net abandonment costs were revised upward to reflect changes in estimates of higher current activity costs and long-term inflation assumptions, primarily in the U.S. During 2020, approximately $23 million net abandonment costs were revised upward to reflect changes in estimates of timing and costs, primarily in the North Sea.

9. DEBT AND FINANCING COSTS

Overview

The debt of Apache and Altus Midstream LP is senior unsecured debt and has equal priority with respect to the payment of both principal and interest. All indentures of Apache for the notes and debentures described below place certain restrictions on Apache, including limits on Apache's ability to incur debt secured by certain liens. Certain of these indentures also restrict Apache's ability to enter into certain sale and leaseback transactions and give holders the option to require Apache to repurchase outstanding notes and debentures upon certain changes in control. None of the indentures contain prepayment obligations in the event of a decline in credit ratings.

On June 19, 2019, Apache closed offerings of $1.0 billion in aggregate principal amount of senior unsecured notes, comprised of $600 million in aggregate principal amount of 4.250% notes due January 15, 2030 and $400 million in aggregate principal amount of 5.350% notes due July 1, 2049. The notes are redeemable at any time, in whole or in part, at Apache's option, subject to a make-whole premium. The net proceeds from the sale of the notes were used to purchase certain outstanding notes in cash tender offers and for general corporate purposes.

On June 21, 2019, Apache closed cash tender offers for certain outstanding notes. Apache accepted for purchase $932 million aggregate principal amount of certain notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of approximately $1.0 billion reflecting principal, the net premium to par, early tender premium, and accrued and unpaid interest. The Company recorded a net loss of $75 million on extinguishment of debt, including $7 million of unamortized debt issuance costs and discount, in connection with the note purchases.

On August 17, 2020, Apache closed offerings of $1.25 billion in aggregate principal amount of senior unsecured notes, comprised of $500 million in aggregate principal amount of 4.625% notes due 2025 and $750 million in aggregate principal amount of 4.875% notes due 2027. The senior unsecured notes are redeemable at any time, in whole or in part, at Apache's option, at the applicable redemption price. The net proceeds from the sale of the notes were used to purchase certain outstanding notes in cash tender offers, repay a portion of outstanding borrowings under Apache's senior revolving credit facility, and for general corporate purposes.

On August 18, 2020, Apache closed cash tender offers for certain outstanding notes. Apache accepted for purchase $644 million aggregate principal amount of certain notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $644 million, reflecting principal, aggregate discount to par of $38 million, early tender premium of $32 million, and accrued and unpaid interest of $6 million. The Company recorded a net gain of $2 million on extinguishment of debt, including an acceleration of unamortized debt discount and issuance costs, in connection with the note purchases.

During 2020, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $588 million for an aggregate purchase price of $428 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $168 million. These repurchases resulted in a $158 million net gain on extinguishment of debt. The net gain includes an acceleration of related discount and debt issuance costs. Additionally, on November 3, 2020, Apache redeemed the remaining $183 million of outstanding 3.625% senior notes due February 1, 2021 at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The repurchases were financed by borrowings under Apache's revolving credit facility.

During the quarter ended September 30, 2021, Apache closed cash tender offers for certain outstanding notes, accepting for purchase $1.7 billion aggregate principal amount of notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $1.8 billion, reflecting principal, premium to par, and accrued and unpaid interest. The Company recognized a $105 million loss on extinguishment of debt, including $11 million of unamortized debt discount and issuance costs, in connection with the note purchases.

During 2021, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $22 million for an aggregate purchase price of $20 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $2 million. The Company recognized a $1 million net gain on extinguishment of debt as part of these transactions.

The Company records gains and losses on extinguishment of debt in "Financing costs, net" in the Company's statement of consolidated operations.

The following table presents the carrying value of the Company's debt:

	December 31, 2021	December 31, 2020
	(In millions)	
3.25% notes due 2022[1][2]	$ 213	$ 213
2.625% notes due 2023[2]	123	123
4.625% notes due 2025[2]	500	500
7.7% notes due 2026	79	79
7.95% notes due 2026	133	133
4.875% due 2027[2]	378	750
4.375% notes due 2028[2]	703	993
7.75% notes due 2029[2][3]	235	235
4.25% notes due 2030[2]	580	580
6.0% notes due 2037[2]	443	443
5.1% notes due 2040[2]	1,333	1,333
5.25% notes due 2042[2]	399	399
4.75% notes due 2043[2]	428	1,133
4.25% notes due 2044[2]	221	559
7.375% debentures due 2047	150	150
5.35% notes due 2049[2]	387	390
7.625% debentures due 2096	39	39
Notes and debentures before unamortized discount and debt issuance costs[4]	6,344	8,052
Commercial paper	—	—
Altus credit facility[5]	657	624
Apache credit facility[5]	542	150
Finance lease obligations	36	38
Unamortized discount	(30)	(35)
Debt issuance costs	(39)	(57)
Total debt	7,510	8,772
Current maturities	(215)	(2)
Long-term debt	$ 7,295	$ 8,770

(1) On January 18, 2022, Apache redeemed the 3.25% senior notes due April 15, 2022, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date.

(2) These notes are redeemable, as a whole or in part, at Apache's option, subject to a make-whole premium, except that the 7.75% notes due 2029 are only redeemable as whole for principal and accrued interest in the event of certain Canadian tax law changes. The remaining notes and debentures are not redeemable.

(3) Assumed by Apache in August 2017 as permitted by terms of these notes originally issued by a subsidiary and guaranteed by Apache.

(4) The fair values of Apache's notes and debentures were $7.1 billion and $8.5 billion as of December 31, 2021 and 2020, respectively. The Company uses a market approach to determine the fair value of its notes and debentures using estimates provided by an independent investment financial data services firm (a Level 2 fair value measurement).

(5) The carrying amount of borrowings on credit facilities approximates fair value because the interest rates are variable and reflective of market rates.

Maturities for the Company's notes and debentures excluding discount and debt issuance costs as of December 31, 2021 are as follows:

	(In millions)
2022	$ 213
2023	123
2024	—
2025	500
2026	212
Thereafter	5,296
Notes and debentures, excluding discounts and debt issuance costs	$ 6,344

Uncommitted Lines of Credit

The Company from time to time has and uses uncommitted credit and letter of credit facilities for working capital and credit support purposes. As of December 31, 2021 and 2020, there were no outstanding borrowings under these facilities. As of December 31, 2021, there were £117 million and $17 million in letters of credit outstanding under these facilities. As of December 31, 2020, there were £34 million and $17 million in letters of credit outstanding under these facilities.

Unsecured Committed Bank Credit Facilities

In March 2018, Apache entered into a revolving credit facility with commitments totaling $4.0 billion. In March 2019, the term of this facility was extended by one year to March 2024 (subject to Apache's remaining one-year extension option) pursuant to Apache's exercise of an extension option. Apache can increase commitments up to $5.0 billion by adding new lenders or obtaining the consent of any increasing existing lenders. The facility includes a letter of credit subfacility of up to $3.0 billion, of which $2.08 billion was committed as of December 31, 2021. The facility is for general corporate purposes. As of December 31, 2021, there were $542 million of borrowings and an aggregate of £748 million and $20 million in letters of credit outstanding under this facility. As of December 31, 2020, there were $150 million of borrowings and an aggregate of £633 million and $40 million in letters of credit outstanding under this facility. The outstanding letters of credit were issued to support North Sea decommissioning obligations, the terms of which required such support after Standard & Poor's reduced Apache's credit rating from BBB to BB+ on March 26, 2020.

At Apache's option, the interest rate per annum for borrowings under the 2018 facility is either a base rate, as defined, plus a margin, or the LIBOR, plus a margin. Apache also pays quarterly a facility fee at a per annum rate on total commitments. The margins and the facility fee vary based upon Apache's senior long-term debt rating. At December 31, 2021, the base rate margin was 0.5 percent, the LIBOR margin was 1.50 percent, and the facility fee was 0.25 percent. A commission is payable quarterly to lenders on the face amount of each outstanding letter of credit at a per annum rate equal to the LIBOR margin then in effect. Customary letter of credit fronting fees and other charges are payable to issuing banks.

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

The 2018 facility's negative covenants restrict the ability of Apache and its subsidiaries to create liens securing debt on its hydrocarbon-related assets, with exceptions for liens typically arising in the oil and gas industry; liens securing debt incurred to finance the acquisition, construction, improvement, or capital lease of assets, provided that such debt, when incurred, does not exceed the subject purchase price and costs, as applicable, and related expenses; liens on subsidiary assets located outside of the U. S. and Canada; and liens arising as a matter of law, such as tax and mechanics' liens. Apache also may incur liens on assets if debt secured thereby does not exceed 15 percent of Apache's consolidated net tangible assets, or approximately $1.9 billion as of December 31, 2021. Negative covenants also restrict Apache's ability to merge with another entity unless it is the surviving entity, dispose of substantially all of its assets, and guarantee debt of non-consolidated entities in excess of the stated threshold.

In November 2018, Altus Midstream LP entered into a revolving credit facility for general corporate purposes that matures in November 2023 (subject to Altus Midstream LP's two, one-year extension options). The agreement for this facility, as amended, provides aggregate commitments from a syndicate of banks of $800 million. All aggregate commitments include a letter of credit subfacility of up to $100 million and a swingline loan subfacility of up to $100 million. Altus Midstream LP may increase commitments up to an aggregate $1.5 billion by adding new lenders or obtaining the consent of any increasing existing lenders. As of December 31, 2021, there were $657 million of borrowings and a $2.0 million of letter of credit outstanding under this facility. As of December 31, 2020, there were $624 million of borrowings and no letters of credit outstanding under this facility.

The agreement for Altus Midstream LP's credit facility, as amended, restricts distributions in respect of capital to ALTM and other unit holders in certain circumstances. Unless the Leverage Ratio is less than or equal to 4.00:1.00, the agreement limits such distributions to $30 million per calendar year until either (i) the consolidated net income of Altus Midstream LP and its restricted subsidiaries, as adjusted pursuant to the agreement, for three consecutive calendar months equals or exceeds $350 million on an annualized basis or (ii) Altus Midstream LP has a specified senior long-term debt rating; in addition, before the occurrence of one of those two events, the Leverage Ratio must be less than or equal to 5.00:1.00. In no event can any distribution be made that would, after giving effect to it on a pro forma basis, result in a Leverage Ratio greater than (i) 5.00:1.00 or (ii) for a specified period after a qualifying acquisition, 5.50:1.00. The Leverage Ratio is the ratio of (1) the consolidated indebtedness of Altus Midstream LP and its restricted subsidiaries to (2) EBITDA (as defined in the agreement) of Altus Midstream LP and its restricted subsidiaries for the 12-month period ending immediately before the determination date. The Leverage Ratio as of December 31, 2021 was less than 4.00:1.00.

The terms of Altus Midstream LP's Preferred Units also contain certain restrictions on distributions in respect of capital, including the common units held by ALTM and any other units that rank junior to the Preferred Units with respect to distributions or distributions upon liquidation. Refer to Note 13—Redeemable Noncontrolling Interest - Altus for further information. In addition, the amount of any cash distributions to Altus Midstream LP by any entity in which it has an interest accounted for by the equity method is subject to such entity's compliance with the terms of any debt or other agreements by which it may be bound, which in turn may impact the amount of funds available for distribution by Altus Midstream LP to its partners.

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

There are no clauses in either the agreement for Apache's 2018 credit facility or for Altus Midstream LP's 2018 credit facility that permit the lenders to accelerate payments or refuse to lend based on unspecified material adverse changes. These agreements do not have drawdown restrictions or prepayment obligations in the event of a decline in credit ratings. However, each agreement allows the lenders to accelerate payment maturity and terminate lending and issuance commitments for nonpayment and other breaches, and if a borrower or any of its subsidiaries defaults on other indebtedness in excess of the stated threshold, is insolvent, or has any unpaid, non-appealable judgment against it for payment of money in excess of the stated threshold. Lenders may also accelerate payment maturity and terminate lending and issuance commitments under the applicable agreement if Apache or Altus Midstream LP, as applicable, undergoes a specified change in control or any borrower has specified pension plan liabilities in excess of the stated threshold. Each of Apache and Altus Midstream LP was in compliance with the terms of its 2018 credit facility as of December 31, 2021.

Commercial Paper Program

As of December 31, 2020, Apache had no commercial paper outstanding. Apache did not use its commercial paper program in 2021 and terminated the program during the third quarter of 2021.

Financing Costs, Net

The following table presents the components of Apache's financing costs, net:

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Interest expense	$ 419	$ 438	$ 430
Amortization of debt issuance costs	8	8	7
Capitalized interest	(9)	(12)	(37)
Loss (gain) on extinguishment of debt	104	(160)	75
Interest income	(8)	(7)	(13)
Financing costs, net	$ 514	$ 267	$ 462

As of December 31, 2021, the Company had $39 million of debt issuance costs, which will be charged to interest expense over the life of the related debt issuances. Discount amortization of $6 million, $7 million, and $2 million was recorded as interest expense in 2021, 2020, and 2019, respectively.

10. INCOME TAXES

Income (loss) before income taxes is composed of the following:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
U.S.	$ 629	$ (4,581)	$ (4,397)
Foreign	1,262	(259)	1,389
Total	$ 1,891	$ (4,840)	$ (3,008)

The total income tax provision consists of the following:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Current income taxes:			
Federal	$ 16	$ (2)	$ 1
Foreign	636	178	659
	652	176	660
Deferred income taxes:			
Federal	—	—	67
Foreign	(74)	(112)	(53)
	(74)	(112)	14
Total	$ 578	$ 64	$ 674

The total income tax provision differs from the amounts computed by applying the U.S. statutory income tax rate to income (loss) before income taxes. A reconciliation of the tax on the Company’s income (loss) before income taxes and total tax expense is shown below:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Income tax expense (benefit) at U.S. statutory rate	$ 397	$ (1,016)	$ (631)
State income tax, less federal effect(1)	—	—	1
Taxes related to foreign operations	298	97	328
Tax credits	(10)	(13)	(6)
Net change in tax contingencies	16	1	1
Goodwill impairment	—	35	—
Valuation allowances(1)	(90)	965	972
Tax attributable to Altus Preferred Unit limited partners	(34)	(16)	(8)
All other, net	1	11	17
	$ 578	$ 64	$ 674

(1) The change in state valuation allowance is included as a component of state income tax.

The net deferred income tax liability reflects the net tax impact of temporary differences between the asset and liability amounts carried on the balance sheet under GAAP and amounts utilized for income tax purposes. The net deferred income tax liability consists of the following as of December 31:

	2021	2020
	(In millions)	
Deferred tax assets:		
U.S. and state net operating losses	$ 2,497	$ 2,306
Capital losses	647	633
Foreign net operating losses	4	—
Tax credits and other tax incentives	24	33
Foreign tax credits	2,241	2,241
Accrued expenses and liabilities	152	93
Asset retirement obligation	712	654
Property and equipment	12	261
Investment in Altus Midstream LP	64	76
Net interest expense limitation	146	252
Lease liability	81	79
Decommissioning contingency for sold Gulf of Mexico properties	263	—
Other	1	1
Total deferred tax assets	6,844	6,629
Valuation allowance	(5,902)	(5,991)
Net deferred tax assets	942	638
Deferred tax liabilities:		
Equity investments	2	4
Property and equipment	748	750
Right-of-use asset	77	74
Decommissioning security for sold Gulf of Mexico properties	164	—
Other	86	13
Total deferred tax liabilities	1,077	841
Net deferred income tax liability	$ 135	$ 203

Net deferred tax assets and liabilities are included in the consolidated balance sheet as of December 31 as follows:

	2021	2020
	(In millions)	
Assets:		
Deferred charges and other	$ 13	$ 12
Liabilities:		
Income taxes	148	215
Net deferred income tax liability	$ 135	$ 203

The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to realize existing deferred tax assets. A significant piece of negative evidence evaluated was the pre-tax book cumulative loss incurred over the three-year period ended December 31, 2021. This cumulative loss was primarily the result of low commodity prices and oil and gas impairments during this period. Such objective evidence limits the ability to consider other subjective evidence, such as the Company’s projections for future growth.

In 2021, 2020, and 2019, the Company's valuation allowance decreased by $89 million, increased by $1.0 billion, and increased by $1.0 billion, respectively, as detailed in the table below:

	2021	2020	2019
		(In millions)	
Balance at beginning of year	$ 5,991	$ 4,959	$ 3,947
State[(1)]	1	67	41
U.S.	(97)	960	971
Foreign	7	5	—
Balance at end of year	$ 5,902	$ 5,991	$ 4,959

(1) Reported as a component of state income taxes.

On December 31, 2021, the Company had net operating losses as follows:

	Amount	Expiration
	(In millions)	
U.S.	$ 9,736	2021 - Indefinite
State	6,697	Various
Foreign	12	2028 - Indefinite

The Company has a U.S. net operating loss carryforward of $9.7 billion, which includes $177 million of net operating loss subject to annual limitation under Section 382 of the Internal Revenue Code (Code). Net operating losses generated in tax years beginning after 2017 are subject to an 80 percent taxable income limitation with indefinite carryover under the 2017 Tax Cuts and Jobs Act. The Company also has a net interest expense carryover of $660 million under Section 163(j) of the Code subject to indefinite carryover, a U.S. capital loss carryforward of $1.9 billion, which has a five year carryover period expiring in 2023 and a Canadian capital loss carryforward of $836 million which has an indefinite carryover. The Company has recorded a full valuation allowance against the U.S. net operating losses, the state net operating losses, the net interest expense carryover, the U.S. capital loss, and the Canadian capital loss because it is more likely than not that these attributes will not be realized.

On December 31, 2021, the Company had foreign tax credits as follows:

	Amount	Expiration
	(In millions)	
Foreign tax credits	$ 2,241	2025-2026

The Company has a $2.2 billion U.S. foreign tax credit carryforward. The Company has recorded a full valuation allowance against the U.S. foreign tax credits listed above because it is more likely than not that these attributes will expire unutilized.

The Company accounts for income taxes in accordance with ASC Topic 740, "Income Taxes," which prescribes a minimum recognition threshold that a tax position must meet before being recognized in the financial statements. Tax positions generally refer to a position taken in a previously filed income tax return or expected to be included in a tax return to be filed in the future that is reflected in the measurement of current and deferred income tax assets and liabilities. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2021	2020	2019
		(In millions)	
Balance at beginning of year	$ 93	$ 82	$ 24
Additions based on tax positions related to prior year	16	—	49
Additions based on tax positions related to the current year	7	11	9
Balance at end of year	$ 116	$ 93	$ 82

The Company records interest and penalties related to unrecognized tax benefits as a component of income tax expense. Each quarter, the Company assesses the amounts provided for and, as a result, may increase or reduce the amount of interest and penalties. During each of the years ended December 31, 2021, 2020, and 2019, the Company recorded tax expense of $1 million for interest and penalties. At December 31, 2021, 2020, and 2019, the Company had an accrued liability for interest and penalties of $4 million, $3 million, and $2 million, respectively.

In 2021, 2020, and 2019, the Company recorded a $23 million net increase, an $11 million net increase, and a $58 million net increase, respectively, in its reserve for uncertain tax positions. The Company is currently under IRS audit for the 2014 through 2017 tax years.

Apache and its subsidiaries are subject to U.S. federal income tax as well as income tax in various states and foreign jurisdictions. The Company's uncertain tax positions are related to tax years that may be subject to examination by the relevant taxing authority. Apache's earliest open tax years in its key jurisdictions are as follows:

Jurisdiction	
U.S.	2014
Egypt	2005
U.K.	2020

11. COMMITMENTS AND CONTINGENCIES

Legal Matters

The Company is party to various legal actions arising in the ordinary course of business, including litigation and governmental and regulatory control, which also may include controls related to the potential impacts of climate changes. As of December 31, 2021, the Company has an accrued liability of approximately $84 million for all legal contingencies that are deemed to be probable of occurring and can be reasonably estimated. The Company's estimates are based on information known about the matters and its experience in contesting, litigating, and settling similar matters. Although actual amounts could differ from management's estimate, none of the actions are believed by management to involve future amounts that would be material to the Company's financial position, results of operations, or liquidity after consideration of recorded accruals. For material matters that the Company believes an unfavorable outcome is reasonably possible, the Company has disclosed the nature of the matter and a range of potential exposure, unless an estimate cannot be made at this time. It is management's opinion that the loss for any other litigation matters and claims that are reasonably possible to occur will not have a material adverse effect on the Company's financial position, results of operations, or liquidity.

Argentine Environmental Claims

On March 12, 2014, the Company and its subsidiaries completed the sale of all of the Company's subsidiaries' operations and properties in Argentina to YPF Sociedad Anonima (YPF). As part of that sale, YPF assumed responsibility for all of the past, present, and future litigation in Argentina involving Company subsidiaries, except that Company subsidiaries have agreed to indemnify YPF for certain environmental, tax, and royalty obligations capped at an aggregate of $100 million. The indemnity is subject to specific agreed conditions precedent, thresholds, contingencies, limitations, claim deadlines, loss sharing, and other terms and conditions. On April 11, 2014, YPF provided its first notice of claims pursuant to the indemnity. Company subsidiaries have not paid any amounts under the indemnity but will continue to review and consider claims presented by YPF. Further, Company subsidiaries retain the right to enforce certain Argentina-related indemnification obligations against Pioneer Natural Resources Company (Pioneer) in an amount up to $45 million pursuant to the terms and conditions of stock purchase agreements entered in 2006 between Company subsidiaries and subsidiaries of Pioneer.

Louisiana Restoration

Louisiana surface owners often file lawsuits or assert claims against oil and gas companies, including the Company, claiming that operators and working interest owners in the chain of title are liable for environmental damages on the leased premises, including damages measured by the cost of restoration of the leased premises to its original condition, regardless of the value of the underlying property. From time to time, restoration lawsuits and claims are resolved by the Company for amounts that are not material to the Company, while new lawsuits and claims are asserted against the Company. With respect to each of the pending lawsuits and claims, the amount claimed is not currently determinable or is not material. Further, the overall exposure related to these lawsuits and claims is not currently determinable. While adverse judgments against the Company are possible, the Company intends to actively defend these lawsuits and claims.

Starting in November of 2013 and continuing into 2021, several parishes in Louisiana have pending lawsuits against many oil and gas producers, including the Company. These cases were all removed to federal courts in Louisiana. In these cases, the Parishes, as plaintiffs, allege that defendants' oil and gas exploration, production, and transportation operations in specified fields were conducted in violation of the State and Local Coastal Resources Management Act of 1978, as amended, and applicable regulations, rules, orders, and ordinances promulgated or adopted thereunder by the Parish or the State of Louisiana. Plaintiffs allege that defendants caused substantial damage to land and water bodies located in the coastal zone of Louisiana. Plaintiffs seek, among other things, unspecified damages for alleged violations of applicable law within the coastal zone, the payment of costs necessary to clear, re-vegetate, detoxify, and otherwise restore the subject coastal zone as near as practicable to its original condition, and actual restoration of the coastal zone to its original condition. While adverse judgments against the Company might be possible, the Company intends to vigorously oppose these claims.

Apollo Exploration Lawsuit

In a case captioned *Apollo Exploration, LLC, Cogent Exploration, Ltd. Co. & SellmoCo, LLC v. Apache Corporation*, Cause No. CV50538 in the 385th Judicial District Court, Midland County, Texas, plaintiffs alleged damages in excess of $200 million (having previously claimed in excess of $1.1 billion) relating to purchase and sale agreements, mineral leases, and area of mutual interest agreements concerning properties located in Hartley, Moore, Potter, and Oldham Counties, Texas. The trial court entered final judgment in favor of the Company, ruling that the plaintiffs take nothing by their claims and awarding the Company its attorneys' fees and costs incurred in defending the lawsuit. The court of appeals affirmed in part and reversed in part the trial court's judgment thereby reinstating some of plaintiff's claims. Further appeal is pending.

Australian Operations Divestiture Dispute

Pursuant to a Sale and Purchase Agreement dated April 9, 2015 (Quadrant SPA), the Company and its subsidiaries divested their remaining Australian operations to Quadrant Energy Pty Ltd (Quadrant). Closing occurred on June 5, 2015. In April 2017, the Company filed suit against Quadrant for breach of the Quadrant SPA. In its suit, the Company seeks approximately AUD $80 million. In December 2017, Quadrant filed a defense of equitable set-off to the Company's claim and a counterclaim seeking approximately AUD $200 million in the aggregate. The Company believes that Quadrant's claims lack merit and will not have a material adverse effect on the Company's financial position, results of operation, or liquidity.

Canadian Operations Divestiture Dispute

Pursuant to a Sale and Purchase Agreement dated July 6, 2017 (Paramount SPA), the Company and its subsidiaries divested their remaining Canadian operations to Paramount Resources LTD (Paramount). Closing occurred on August 16, 2017. On September 11, 2019, four ex-employees of Apache Canada LTD on behalf of themselves and individuals employed by Apache Canada LTD on July 6, 2017, filed an Amended Statement of Claim in a matter styled *Stephen Flesch et. al. v Apache Corporation et. al*., No. 1901-09160 Court of Queen's Bench of Alberta against the Company and others seeking class certification and a finding that the Paramount SPA amounted to a Change of Control of the Company, entitling them to accelerated vesting under the Company's equity plans. In the suit, the class seeks approximately $60 million USD and punitive damages. The Company believes that Plaintiffs' claims lack merit and will not have a material adverse effect on the Company's financial position, results of operation, or liquidity.

California and Delaware Litigation

On July 17, 2017, in three separate actions, San Mateo County, California, Marin County, California, and the City of Imperial Beach, California, all filed suit individually and on behalf of the people of the state of California against over 30 oil and gas companies alleging damages as a result of global warming. Plaintiffs seek unspecified damages and abatement under various tort theories. On December 20, 2017, in two separate actions, the City of Santa Cruz and Santa Cruz County and in a separate action on January 22, 2018, the City of Richmond, filed similar lawsuits against many of the same defendants. On November 14, 2018, the Pacific Coast Federation of Fishermen's Associations, Inc. also filed a similar lawsuit against many of the same defendants. After removal of all such lawsuits to federal court, the district court remanded them back to state court. The 9th Circuit Court of Appeals' affirmance of this remand decision was appealed to the U.S. Supreme Court. That appeal was decided by the U.S. Supreme Court ruling in a similar case, *BP p.l.c. v. Mayor and City Council of Baltimore*. As a result, the California cases have been sent back to the 9th Circuit for further appellate review of the decision to remand the cases to state court. Further activity in the cases has been stayed pending further appellate review.

On September 10, 2020, the State of Delaware filed suit, individually and on behalf of the people of the State of Delaware, against over 25 oil and gas companies alleging damages as a result of global warming. Plaintiffs seek unspecified damages and abatement under various tort theories. After removal of this lawsuit to federal court, the district court remanded it back to state court. The remand order is being appealed to the 3rd Circuit Court of Appeals. Further activity in the case has been stayed pending this appellate review.

The Company believes that it is not subject to jurisdiction of the California courts and that claims made against it in the California and Delaware litigation are baseless. The Company intends to challenge jurisdiction in California and to vigorously defend the Delaware lawsuit.

Castex Lawsuit

In a case styled *Apache Corporation v. Castex Offshore, Inc., et. al.*, Cause No. 2015-48580, in the 113th Judicial District Court of Harris County, Texas, Castex filed claims for alleged damages of approximately $200 million, relating to overspend on the Belle Isle Gas Facility upgrade, and the drilling of five sidetracks on the Potomac #3 well. After a jury trial, a verdict of approximately $60 million, plus fees, costs, and interest was entered against the Company. The Fourteenth Court of Appeals of Texas reversed the judgment, in part, reducing the judgment to approximately $13.5 million, plus fees, costs, and interest against the Company. Further appeal is pending.

Oklahoma Class Actions

The Company is a party to two purported class actions in Oklahoma styled *Bigie Lee Rhea v. Apache Corporation*, Case No. 6:14-cv-00433-JH, and *Albert Steven Allen v. Apache Corporation*, Case No. CJ-2019-00219. The *Rhea* case has been certified and includes a class of royalty owners seeking damages of approximately $200 million for alleged breach of the implied covenant to market relating to post-production deductions and alleged NGL uplift value. The *Allen* case has not been certified and seeks to represent a group of owners who have allegedly received late royalty and other payments under Oklahoma statutes. Without acknowledging or admitting any liability and solely to avoid the expense and uncertainty of future litigation, Apache has agreed to a settlement in the *Rhea* case under which Apache will pay $25 million to resolve all claims against the Company asserted by the class. The settlement is subject to court approval and is expected to be finalized in the first quarter of 2022.

Shareholder and Derivative Lawsuits

On February 23, 2021, a case captioned *Plymouth County Retirement System v. Apache Corporation, et al.* was filed in the United States District Court for the Southern District of Texas (Houston Division) against the Company and certain current and former officers. The complaint, which is a shareholder lawsuit styled as a class action, (1) alleges that the Company intentionally used unrealistic assumptions regarding the amount and composition of available oil and gas in Alpine High; (2) alleges that the Company did not have the proper infrastructure in place to safely and/or economically drill and/or transport those resources even if they existed in the amounts purported; (3) alleges that these statements and omissions artificially inflated the value of the Company's operations in the Permian Basin; and (4) alleges that, as a result, the Company's public statements were materially false and misleading. The Company believes that plaintiffs' claims lack merit and intends to vigorously defend this lawsuit.

On March 16, 2021, a case captioned *William Wessels, Derivatively and on behalf of APA Corporation v. John J. Christmann IV et al.* was filed in the 334th District Court of Harris County, Texas. The case purports to be a derivative action brought against senior management and Company directors over many of the same allegations included in the *Plymouth County Retirement System* matter and asserts claims of (1) breach of fiduciary duty; (2) waste of corporate assets; and (3) unjust enrichment. The defendants believe the plaintiff's claims lack merit and intend to vigorously defend this lawsuit.

Environmental Matters

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state, local, and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a Company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, the amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to the Company's satisfaction, or agree to assume liability for the remediation of the property. The Company's general policy is to limit any reserve additions to any incidents or sites that are considered probable to result in an expected remediation cost exceeding $300,000. Any environmental costs and liabilities that are not reserved for are treated as an expense when actually incurred. In the Company's estimation, neither these expenses nor expenses related to training and compliance programs are likely to have a material impact on its financial condition.

As of December 31, 2021, the Company had an undiscounted reserve for environmental remediation of approximately $2 million.

On September 11, 2020, the Company received a Notice of Violation and Finding of Violation, and accompanying Clean Air Act Information Request, from the U.S. Environmental Protection Agency (EPA) following site inspections in April 2019 at several of the Company's oil and natural gas production facilities in Lea and Eddy Counties, New Mexico. The notice and information request involve alleged emissions control and reporting violations. The Company is cooperating with the EPA and has responded to the information request. The EPA has referred the notice for civil enforcement proceedings; however, at this time the Company is unable to reasonably estimate whether such proceedings will result in monetary sanctions and, if so, whether they would be more or less than $100,000, exclusive of interest and costs.

On December 29, 2020, the Company received a Notice of Violation and Opportunity to Confer, and accompanying Clean Air Act Information Request, from the EPA following helicopter flyovers in September 2019 of several of the Company's oil and natural gas production facilities in Reeves County, Texas. The notice and information request involve alleged emissions control and reporting violations. The Company is cooperating with the EPA and has responded to the information request. The EPA has referred the notice for civil enforcement proceedings; however, at this time the Company is unable to reasonably estimate whether such proceedings will result in monetary sanctions and, if so, whether they would be more or less than $100,000, exclusive of interest and costs.

The Company is not aware of any environmental claims existing as of December 31, 2021 that have not been provided for or would otherwise have a material impact on its financial position, results of operations, or liquidity. There can be no assurance, however, that current regulatory requirements will not change or past non-compliance with environmental laws will not be discovered on the Company's properties.

Potential Decommissioning Obligations on Sold Properties

In 2013, Apache sold its Gulf of Mexico (GOM) Shelf operations and properties and its GOM operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Under the terms of the purchase agreement, Apache received cash consideration of $3.75 billion and Fieldwood assumed the obligation to decommission the properties held by GOM Shelf and the properties acquired from Apache and its other subsidiaries (collectively, the Legacy GOM Assets). In respect of such abandonment obligations, Fieldwood posted letters of credit in favor of Apache (Letters of Credit) and established trust accounts (Trust A and Trust B) of which Apache was a beneficiary and which were funded by two net profits interests (NPIs) depending on future oil prices. On February 14, 2018, Fieldwood filed for protection under Chapter 11 of the U.S. Bankruptcy Code. In connection with the 2018 bankruptcy, Fieldwood confirmed a plan under which Apache agreed, inter alia, to (i) accept bonds in exchange for certain of the Letters of Credit and (ii) amend the Trust A trust agreement and one of the NPIs to consolidate the trusts into a single Trust (Trust A) funded by both remaining NPIs. Currently, Apache holds two bonds (Bonds) and five Letters of Credit to secure Fieldwood's asset retirement obligations on the Legacy GOM Assets as and when Apache is required to perform or pay for decommissioning any Legacy GOM Asset over the remaining life of the Legacy GOM Assets.

On August 3, 2020, Fieldwood again filed for protection under Chapter 11 of the U.S. Bankruptcy Code. On June 25, 2021, the United States Bankruptcy Court for the Southern District of Texas (Houston Division) entered an order confirming Fieldwood's bankruptcy plan. On August 27, 2021, Fieldwood's bankruptcy plan became effective. Pursuant to the plan, the Legacy GOM Assets were separated into a standalone company, which was subsequently merged into GOM Shelf. Under GOM Shelf's limited liability company agreement, the proceeds of production of the Legacy GOM Assets will be used to fund decommissioning of Legacy GOM Assets.

In September 2021, GOM Shelf notified the Bureau of Safety and Environmental Enforcement (BSEE) that it was unable to fund the decommissioning obligations that it is currently obligated to perform on certain of the Legacy GOM Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE to decommission certain of the Legacy GOM Assets included in GOM Shelf's notification to BSEE. Apache expects to receive such orders on the other Legacy GOM Assets included in GOM Shelf's notification letter. Further, Apache anticipates that GOM Shelf may send additional such notices to BSEE in the future and that it may receive additional orders from BSEE requiring it to decommission other Legacy GOM Assets.

If Apache incurs costs to decommission any Legacy GOM Asset and GOM Shelf does not reimburse Apache for such costs, then Apache will obtain reimbursement from Trust A, the Bonds, and the Letters of Credit until such funds and securities are fully utilized. In addition, after such sources have been exhausted, Apache has agreed to provide a standby loan to GOM Shelf of up to $400 million to perform decommissioning (Standby Loan Agreement), with such standby loan secured by a first and prior lien on the Legacy GOM Assets.

If the combination of GOM Shelf's net cash flow from its producing properties, the Trust A funds, the Bonds, and the remaining Letters of Credit are insufficient to fully fund decommissioning of any Legacy GOM Assets that Apache may be ordered by BSEE to perform, or if GOM Shelf's net cash flow from its remaining producing properties after the Trust A funds, Bonds, and Letters of Credit are exhausted is insufficient to repay any loans made by Apache under the Standby Loan Agreement, then Apache may be forced to effectively use its available cash to fund the deficit.

As of December 31, 2021, Apache estimates that its potential liability to fund decommissioning of Legacy GOM Assets it may be ordered to perform ranges from $1.2 billion to $1.4 billion on an undiscounted basis. Management does not believe any specific estimate within this range is a better estimate than any other. Accordingly, during 2021, the Company recorded a contingent liability of $1.2 billion, representing the estimated costs of decommissioning it may be required to perform on Legacy GOM Assets. Of the total liability recorded, $1.1 billion is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $100 million is reflected under "Other current liabilities" in the Company's consolidated balance sheet. The Company also recorded a $740 million asset, which represents the amount the Company expects to be reimbursed from the Trust A funds, the Bonds, and the Letters of Credit for decommissioning it may be required to perform on Legacy GOM Assets. Of the total asset recorded, $640 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $100 million is reflected under "Other current assets." A "Loss on previously sold Gulf of Mexico properties" in the amount of $446 million was recognized in the third quarter of 2021 to reflect the net impact to the Company's statement of consolidated operations. Changes in significant assumptions impacting Apache's estimated liability, including expected decommissioning rig spread rates, lift boat rates, and planned abandonment logistics could result in a liability in excess of the amount accrued. In addition, significant changes in the market price of oil, gas, and NGLs could further impact Apache's estimate of its contingent liability to decommission Legacy GOM Assets.

Leases and Contractual Obligations

On January 1, 2019, the Company adopted ASU 2016-02, "Leases (Topic 842)," which requires lessees to recognize separate right-of-use (ROU) assets and lease liabilities for most leases classified as operating leases under previous GAAP. As allowed under the standard, the Company applied practical expedients permitting an entity the option to not evaluate under ASU 2016-02 those existing or expired land easements that were not previously accounted for as leases, as well as permitting an entity the option to carry forward its historical assessments of whether existing agreements contain a lease, classification of existing lease agreements, and treatment of initial direct lease costs.

The Company determines if an arrangement is an operating or finance lease at the inception of each contract. If the contract is classified as an operating lease, the Company records an ROU asset and corresponding liability reflecting the total remaining present value of fixed lease payments over the expected term of the lease agreement. The expected term of the lease may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. If the Company's lease does not provide an implicit rate in the contract, the Company uses its incremental borrowing rate when calculating the present value. In the normal course of business, the Company enters into various lease agreements for real estate, drilling rigs, vessels, aircrafts, and equipment related to its exploration and development activities, which are typically classified as operating leases under the provisions of the standard. ROU assets are reflected within "Deferred charges and other assets" on the Company's consolidated balance sheet, and the associated operating lease liabilities are reflected within "Other current liabilities" and "Other" within "Deferred Credits and Other Noncurrent Liabilities," as applicable.

Operating lease expense associated with ROU assets is recognized on a straight-line basis over the lease term. Lease expense is reflected on the statement of consolidated operations commensurate with the leased activities and nature of the services performed. Gross fixed operating lease expense, inclusive of amounts billable to partners and other working interest owners, was $128 million, $149 million, and $222 million for the full years of 2021, 2020, and 2019, respectively. The Company elected to exclude short-term leases (those with terms of 12 months or less) from the balance sheet presentation. Costs incurred for short-term leases, which is primarily related to drilling activities in Block 58 offshore Suriname, was $20 million, $80 million and $18 million in 2021, 2020, and 2019, respectively.

In addition, the Company periodically enters into finance leases that are similar to those leases classified as capital leases under previous GAAP. Finance lease assets are included in “Property, Plant, and Equipment” on the consolidated balance sheet, and the associated finance lease liabilities are reflected within “Current debt” and “Long-term debt,” as applicable. Depreciation on the Company’s finance lease asset was $2 million, $2 million, and $7 million in 2021, 2020, and 2019, respectively. Interest on the Company’s finance lease asset was $2 million, $2 million, and $3 million in 2021, 2020, and 2019, respectively.

The following table represents the Company’s weighted average lease term and discount rate as of December 31, 2021:

	Operating Leases	Finance Leases
Weighted average remaining lease term	3.4 years	11.7 years
Weighted average discount rate	3.7 %	4.4 %

At December 31, 2021, contractual obligations for long-term operating leases, finance leases, and purchase obligations are as follows:

Net Minimum Commitments[1]	Operating Leases[2]	Finance Leases[3]	Purchase Obligations[4][5]
		(In millions)	
2022	$ 106	$ 3	$ 226
2023	76	3	198
2024	58	3	161
2025	7	4	159
2026	7	4	3,637
Thereafter	18	25	473
Total future minimum payments	272	42	$ 4,854
Less: imputed interest	(21)	(6)	N/A
Total lease liabilities	251	36	N/A
Current portion	99	2	N/A
Non-current portion	$ 152	$ 34	N/A

(1) Excludes commitments for jointly owned fields and facilities for which the Company is not the operator.

(2) Amounts represent future payments associated with oil and gas operations inclusive of amounts billable to partners and other working interest owners. Such payments may be capitalized as a component of oil and gas properties and subsequently depreciated, impaired, or written off as exploration expense.

(3) Amounts represent the Company’s finance lease obligation related to the Company’s Midland, Texas regional office building.

(4) Amounts represent any agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, drilling work program commitments, and agreements to secure capacity rights on third-party pipelines. Amounts exclude certain product purchase obligations related to marketing and trading activities for which there are no minimum purchase requirements or the amounts are not fixed or determinable. Total costs incurred under take-or-pay and throughput obligations were $198 million, $120 million, and $111 million in 2021, 2020, and 2019, respectively.

(5) Under terms agreed to in the Egypt modernized PSC, the Company committed to spend a minimum of $3.5 billion on exploration, development, and operating activities by March 31, 2026. The Company believes it will be able to satisfy this obligation within its current exploration and development program.

The lease liability reflected in the table above represents the Company’s fixed minimum payments that are settled in accordance with the lease terms. Actual lease payments during the period may also include variable lease components such as common area maintenance, usage-based sales taxes and rate differentials, or other similar costs that are not determinable at the inception of the lease. Gross variable lease payments, inclusive of amounts billable to partners and other working interest owners were $64 million, $41 million, and $78 million in 2021, 2020, and 2019, respectively.

12. RETIREMENT AND DEFERRED COMPENSATION PLANS

The Company provides retirement benefits to its U.S. employees through the use of multiple plans: a 401(k) savings plan, a money purchase retirement plan, a non-qualified retirement savings plan, and a non-qualified restorative retirement savings plan. The 401(k) savings plan provides participating employees the ability to elect to contribute up to 50 percent of eligible compensation, as defined, to the plan with the Company making matching contributions up to a maximum of 8 percent of each employee's annual eligible compensation. In addition, the Company contributes 6 percent of each participating employee's annual eligible compensation to a money purchase retirement plan. The 401(k) savings plan and the money purchase retirement plan are subject to certain annually-adjusted, government-mandated restrictions that limit the amount of employee and Company contributions. For certain eligible employees, the Company also provides a non-qualified retirement savings plan or a non-qualified restorative retirement savings plan. These plans allow the deferral of up to 50 percent of eligible employee's base salary, up to 75 percent of each employee's annual bonus (that accepts employee contributions) and the Company's matching contributions in excess of the government mandated limitations imposed in the 401(k) savings plan and money purchase retirement plan.

Vesting in the Company's contributions in the 401(k) savings plan, the money purchase retirement plan, the non-qualified retirement savings plan and the non-qualified restorative retirement savings plan occurs at the rate of 20 percent for every completed year of employment. Upon a qualifying change in control of ownership of APA, immediate and full vesting occurs.

Additionally, Apache North Sea Limited maintains a separate retirement plan, as required under the laws of the U.K.

The aggregate annual cost to the Company of all U.S. and international savings plans, the money purchase retirement plan, non-qualified retirement savings plan, and non-qualified restorative retirement savings plan was $31 million, $43 million, and $52 million for 2021, 2020, and 2019, respectively.

The Company also provides a funded noncontributory defined benefit pension plan (U.K. Pension Plan) covering certain employees of the Company's North Sea operations in the U.K. The plan provides defined pension benefits based on years of service and final salary. The plan applies only to employees who were part of BP North Sea's pension plan as of April 2, 2003, prior to the acquisition of BP North Sea by the Company effective July 1, 2003.

Additionally, the Company offers postretirement medical benefits to U.S. employees who meet certain eligibility requirements. Eligible participants receive medical benefits up until the age of 65 or at the date they become eligible for Medicare, provided the participant remits the required portion of the cost of coverage. The plan is contributory with participants' contributions adjusted annually. The postretirement benefit plan does not cover benefit expenses once a covered participant becomes eligible for Medicare.

The following tables set forth the benefit obligation, fair value of plan assets and funded status as of December 31, 2021, 2020, and 2019, and the underlying weighted average actuarial assumptions used for the U.K. Pension Plan and U.S. postretirement benefit plan. The Company uses a measurement date of December 31 for its pension and postretirement benefit plans.

	2021		2020		2019	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Change in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	$ 233	$ 20	$ 199	$ 20	$ 187	$ 27
Service cost	3	1	3	1	3	2
Interest cost	3	—	4	—	5	1
Foreign currency exchange rates	(2)	—	8	—	7	—
Actuarial losses (gains)	(5)	1	30	1	15	(9)
Plan settlements	(17)	—	—	—	(14)	—
Benefits paid	(4)	(4)	(11)	(4)	(4)	(2)
Retiree contributions	—	2	—	2	—	1
Projected benefit obligation at end of year	211	20	233	20	199	20
Change in Plan Assets						
Fair value of plan assets at beginning of year	262	—	228	—	208	—
Actual return on plan assets	11	—	31	—	25	—
Foreign currency exchange rates	(3)	—	9	—	8	—
Employer contributions	5	2	5	2	5	1
Plan settlements	(17)	—	—	—	(14)	—
Benefits paid	(4)	(4)	(11)	(4)	(4)	(2)
Retiree contributions	—	2	—	2	—	1
Fair value of plan assets at end of year	254	—	262	—	228	—
Funded status at end of year	$ 43	$ (20)	$ 29	$ (20)	$ 29	$ (20)
Amounts recognized in Consolidated Balance Sheet						
Current liability	$ —	$ (2)	$ —	$ (2)	$ —	$ (2)
Non-current asset (liability)	43	(18)	29	(18)	29	(18)
	$ 43	$ (20)	$ 29	$ (20)	$ 29	$ (20)
Pre-tax Amounts Recognized in Accumulated Other Comprehensive Income (Loss)						
Accumulated gain (loss)	$ 1	$ 14	$ (11)	$ 16	$ (7)	$ 19
Weighted Average Assumptions used as of December 31						
Discount rate	1.80 %	2.57 %	1.40 %	2.06 %	2.10 %	3.00 %
Salary increases	4.90 %	N/A	4.50 %	N/A	4.30 %	N/A
Expected return on assets	1.90 %	N/A	1.50 %	N/A	2.20 %	N/A
Healthcare cost trend						
Initial	N/A	6.25 %	N/A	6.00 %	N/A	6.25 %
Ultimate in 2028	N/A	5.00 %	N/A	5.00 %	N/A	5.00 %

As of December 31, 2021, 2020, and 2019, the accumulated benefit obligation for the U.K. Pension Plan was $205 million, $207 million, and $181 million, respectively.

The Company's defined benefit pension plan assets are held by a non-related trustee who has been instructed to invest the assets in a blend of equity securities and low-risk debt securities. The Company intends that this blend of investments will provide a reasonable rate of return such that the benefits promised to members are provided. The U.K. Pension Plan policy is to target an ongoing funding level of 100 percent through prudent investments and includes policies and strategies such as investment goals, risk management practices, and permitted and prohibited investments. A breakout of previous allocations for plan asset holdings and the target allocation for the Company's plan assets are summarized below:

	Target Allocation	Percentage of Plan Assets at Year-End	
	2021	2021	2020
Asset Category			
Equity securities:			
Overseas quoted equities	15 %	15 %	19 %
Total equity securities	15 %	15 %	19 %
Debt securities:			
U.K. government bonds	55 %	54 %	64 %
U.K. corporate bonds	24 %	25 %	16 %
Total debt securities	79 %	79 %	80 %
Cash	6 %	6 %	1 %
Total	100 %	100 %	100 %

The plan's assets do not include any direct ownership of equity or debt securities of the Company. The fair value of plan assets at December 31, 2021 and 2020 are based upon unadjusted quoted prices for identical instruments in active markets, which is a Level 1 fair value measurement. The following tables present the fair values of plan assets for each major asset category based on the nature and significant concentration of risks in plan assets at December 31, 2021 and 2020:

	December 31,	
	2021	2020
	(In millions)	
Equity securities:		
Overseas quoted equities	$ 38	$ 49
Total equity securities	38	49
Debt securities:		
U.K. government bonds	138	168
U.K. corporate bonds	62	43
Total debt securities	200	211
Cash	16	2
Fair value of plan assets	$ 254	$ 262

The expected long-term rate of return on assets assumptions are derived relative to the yield on long-dated fixed-interest bonds issued by the U.K. government (gilts). For equities, outperformance relative to gilts is assumed to be 3.5 percent per year.

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions used for the pension and postretirement benefit plans as of December 31, 2021, 2020, and 2019:

	2021		2020		2019	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
			(In millions)			
Components of Net Periodic Benefit Cost						
Service cost	$ 3	$ 1	$ 3	$ 1	$ 3	$ 2
Interest cost	3	—	4	—	5	1
Expected return on assets	(4)	—	(5)	—	(5)	—
Amortization of loss	—	(1)	—	(1)	—	(1)
Settlement loss	—	—	—	—	—	—
Net periodic benefit cost	$ 2	$ —	$ 2	$ —	$ 3	$ 2
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31						
Discount rate	1.40 %	2.06 %	2.10 %	3.00 %	2.90 %	4.13 %
Salary increases	4.50 %	N/A	4.30 %	N/A	4.70 %	N/A
Expected return on assets	1.50 %	N/A	2.20 %	N/A	2.80 %	N/A
Healthcare cost trend						
Initial	N/A	6.00 %	N/A	6.25 %	N/A	6.50 %
Ultimate in 2025	N/A	5.00 %	N/A	5.00 %	N/A	5.00 %

The Company expects to contribute approximately $5 million to its pension plan and $2 million to its postretirement benefit plan in 2022. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Postretirement Benefits
	(In millions)	
2022	$ 6	$ 2
2023	7	2
2024	6	2
2025	6	2
2026	6	2
Years 2027-2031	39	6

13. REDEEMABLE NONCONTROLLING INTEREST — ALTUS

Preferred Units Issuance

On June 12, 2019, Altus Midstream LP issued and sold Preferred Units for an aggregate issue price of $625 million in a private offering exempt from the registration requirements of the Securities Act of 1933, as amended (the Closing). Altus Midstream LP received approximately $611 million in cash proceeds from the sale after deducting transaction costs and discounts to certain purchasers. Pursuant to the partnership agreement of Altus Midstream LP:

- The Preferred Units bear quarterly distributions at a rate of 7 percent per annum, increasing to 10 percent per annum after the fifth anniversary of Closing and upon the occurrence of specified events. Altus Midstream LP may pay distributions in-kind for the first six quarters after the Preferred Units are issued.
- The Preferred Units are redeemable at Altus Midstream LP’s option at any time in cash at a redemption price (the Redemption Price) equal to the greater of an 11.5 percent internal rate of return (increasing after the fifth anniversary of Closing to 13.75 percent) and a 1.3x multiple of invested capital. The Preferred Units will be redeemable at the holder’s option upon a change of control or liquidation of Altus Midstream LP and certain other events, including certain asset dispositions.
- The Preferred Units will be exchangeable for shares of ALTM’s Class A common stock at the holder’s election after the seventh anniversary of Closing or upon the occurrence of specified events. Each Preferred Unit will be exchangeable for a number of shares of ALTM’s Class A common stock equal to the Redemption Price divided by the volume-weighted average trading price of ALTM’s Class A common stock on the Nasdaq Capital Market for the 20 trading days immediately preceding the second trading day prior to the applicable exchange date, less a 6 percent discount.
- Each outstanding Preferred Unit has a liquidation preference equal to the Redemption Price payable before any amounts are paid in respect of Altus Midstream LP’s common units and any other units that rank junior to the Preferred Units with respect to distributions or distributions upon liquidation.
- Preferred Units holders have rights to approve certain partnership business, financial, and governance-related matters.
- Altus Midstream LP is restricted from declaring or making cash distributions on its common units until all required distributions on the Preferred Units have been paid. In addition, before the fifth anniversary of Closing, aggregate cash distributions on, and redemptions of, Altus Midstream LP’s common units are limited to $650 million of cash from ordinary course operations if permitted under its credit facility. Cash distributions on, and redemptions of, Altus Midstream LP’s common units also are subject to satisfaction of leverage ratio requirements specified in its partnership agreement.

Classification

The Preferred Units are accounted for on the Company’s consolidated balance sheets as a redeemable noncontrolling interest classified as temporary equity based on the terms of the Preferred Units, including the redemption rights with respect thereto.

Initial Measurement

Altus recorded the net transaction price of $611 million, calculated as the negotiated transaction price of $625 million, less issue discounts of $4 million and transaction costs totaling $10 million.

Certain redemption features embedded within the terms of the Preferred Units require bifurcation and measurement at fair value. Altus bifurcated and recognized at fair value an embedded derivative related to the Preferred Units at inception of $94 million for a redemption option of the Preferred Unit holders. The derivative is reflected in “Other” within “Deferred Credits and Other Noncurrent Liabilities” on the Company’s consolidated balance sheet at its current fair value of $57 million as of December 31, 2021. The fair value of the embedded derivative, a Level 3 fair value measurement, was based on numerous factors including expected future interest rates using the Black-Karasinski model, Altus’ imputed interest rate, the timing of periodic cash distributions, and dividend yields of the Preferred Units. Refer to Note 4—Derivative Instruments and Hedging Activities for more detail.

The net transaction price was allocated to the preferred redeemable noncontrolling interest and the embedded features according to the associated initial fair value measurements as follows:

	June 12, 2019
	(In millions)
Redeemable noncontrolling interest - Altus Preferred Unit limited partners	$ 517
Preferred Units embedded derivative	94
	$ 611

Subsequent Measurement

Altus applies a two-step approach to subsequent measurement of the redeemable noncontrolling interest related to the Preferred Units by first allocating a portion of the net income of Altus Midstream LP in accordance with the terms of the partnership agreement. An additional adjustment to the carrying value of the Preferred Unit redeemable noncontrolling interest at each period end may be recorded, if applicable. The amount of such adjustment is determined based upon the accreted value method to reflect the passage of time until the Preferred Units are exchangeable at the option of the holder. Pursuant to this method, the net transaction price is accreted using the effective interest method to the Redemption Price calculated at the seventh anniversary of the Closing. The total adjustment is limited to an amount such that the carrying amount of the Preferred Unit redeemable noncontrolling interest at each period end is equal to the greater of (a) the sum of (i) the carrying amount of the Preferred Units, plus (ii) the fair value of the embedded derivative liability and (b) the accreted value of the net transaction price.

Activity related to the Preferred Units for the years ended December 31, 2021 and 2020 is as follows:

	Units Outstanding	Financial Position[(1)]
	(In millions, except unit data)	
Redeemable noncontrolling interest — Preferred Units: at December 31, 2019	638,163	$ 555
Distribution of in-kind additional Preferred Units	22,531	—
Cash distributions paid to Preferred Unit limited partners	—	(23)
Allocation of Altus Midstream net income	N/A	76
Redeemable noncontrolling interest - Altus Preferred Unit limited partners: at December 31, 2020	660,694	608
Cash distributions to Altus Preferred Unit limited partners	—	(46)
Distributions payable to Altus Preferred Unit limited partners	—	(12)
Allocation of Altus Midstream LP net income	N/A	80
Accreted value adjustment	N/A	82
Redeemable noncontrolling interest - Altus Preferred Unit limited partners: at December 31, 2021	660,694	712
Preferred Units embedded derivative[(2)]		57
		$ 769

(1) The Preferred Units are redeemable at Altus Midstream LP’s option at a redemption price (the Redemption Price), which as of December 31, 2021 is calculated as the greater of (i) an 11.5 percent internal rate of return and (ii) a 1.3 times multiple of invested capital. As of December 31, 2021, the Redemption Price would have been based on an 11.5 percent internal rate of return, which would equate to a redemption value of $739 million.

(2) Certain redemption features embedded within the terms of the Preferred Units require bifurcation and measurement at fair value. Refer to Note 4—Derivative Instruments and Hedging Activities for discussion of the fair value changes in the embedded derivative liability during the period.

N/A - not applicable.

14. CAPITAL STOCK

Common Stock Outstanding

The following table provides changes to the Company's common shares outstanding for the years ended December 31, 2021, 2020, and 2019:

	For the Year Ended December 31,		
	2021	2020	2019
Balance, beginning of year	377,482,630	376,062,670	374,696,222
Shares issued for stock-based compensation plans:			
Treasury shares issued	3,133	17,448	31,701
Common shares issued	649,231	1,402,512	1,334,747
Treasury shares acquired	(31,204,229)	—	—
Balance, end of year	346,930,765	377,482,630	376,062,670

Net Income (Loss) per Common Share

The following table provides a reconciliation of the components of basic and diluted net income (loss) per common share for the years ended December 31, 2021, 2020, and 2019:

	2021			2020			2019		
	Income	Shares	Per Share	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In millions, except per share amounts)								
Basic:									
Income (loss) attributable to common stock	$ 973	374	$ 2.60	$ (4,860)	378	$ (12.86)	$ (3,553)	377	$ (9.43)
Effect of Dilutive Securities:									
Stock options and other	$ —	1	$ (0.01)	$ —	—	$ —	$ —	—	$ —
Diluted:									
Income (loss) attributable to common stock	$ 973	375	$ 2.59	$ (4,860)	378	$ (12.86)	$ (3,553)	377	$ (9.43)

The diluted EPS calculation excludes options and restricted shares that were anti-dilutive totaling 3.3 million, 4.5 million, and 5.0 million for the years ended December 31, 2021, 2020, and 2019, respectively. The impact to net income (loss) attributable to common stock on an assumed conversion of the redeemable noncontrolling Preferred Units interest in Altus Midstream LP was anti-dilutive for the years ended December 31, 2021, 2020 and 2019.

Stock Repurchase Program

During 2018, the Company's Board of Directors authorized the purchase of up to 40 million shares of the Company's common stock. No shares were purchased under this authorization through December 31, 2020. During 2021, the Company's Board of Directors authorized the purchase of an additional 40 million shares of the Company's common stock. Shares may be purchased either in the open market or through privately held negotiated transactions.

In the fourth quarter of 2021, the Company repurchased 31.2 million shares at an average price of $27.14 per share, and as of December 31, 2021, the Company had remaining authorization to repurchase 48.8 million shares. The Company is not obligated to acquire any additional shares.

Common Stock Dividend

In the first quarter of 2020, the Company's Board of Directors approved a reduction in the Company's quarterly dividends from $0.25 per share to $0.025 per share, effective for all dividends payable after March 12, 2020. During the third quarter of 2021, the Company's Board of Directors approved an increase in its quarterly dividend from $0.025 per share to $0.0625 per share, and in the fourth quarter of 2021, approved a further increase in its quarterly dividend to $0.125 per share. For the years ended December 31, 2021, 2020, and 2019, the Company declared common stock dividends totaling $0.2375 per share, $0.10 per share, and $1.00 per share, respectively.

Stock Compensation Plans

The Company maintains several stock-based compensation plans, which include stock options, restricted stock, and conditional restricted stock unit plans. In 2021, pursuant to the Holding Company Reorganization, Apache's outstanding common shares were converted into equivalent corresponding shares of APA. APA assumed sponsorship of all stock compensation plans. All cash-settled awards previously indexed to Apache's stock price were subsequently indexed to APA's stock price, and all unvested stock-settled awards will be settled in APA stock upon vesting.

On May 12, 2016, the Company's shareholders approved the 2016 Omnibus Compensation Plan (the 2016 Plan), which is used to provide eligible employees with equity-based incentives by granting incentive stock options, non-qualified stock options, performance awards, restricted stock awards, restricted stock units, stock appreciation rights, cash awards, or any combination of the foregoing. As of December 31, 2021, 11.0 million shares were authorized and available for grant under the 2016 Plan. Previously approved plans remain in effect solely for the purpose of governing grants still outstanding that were issued prior to approval of the 2016 Plan. All new grants are issued from the 2016 Plan. In 2018, the Company began issuing cash-settled awards (phantom units) under the restricted stock and conditional restricted stock unit plans. The phantom units represent a hypothetical interest in the Company's stock and, once vested, are settled in cash.

Costs related to the plans are capitalized or expensed to "Lease operating expenses," "Exploration," or "General and administrative" in the Company's statement of consolidated operations based on the nature of each employee's activities. The following table summarizes the Company's stock-settled and cash-settled compensation costs:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Stock-settled and cash-settled compensation expensed	$ 157	$ 40	$ 110
Stock-settled and cash-settled compensation capitalized	18	7	28
Total stock-settled and cash-settled compensation costs	$ 175	$ 47	$ 138

Stock Options

As of December 31, 2021, the Company had outstanding options to purchase shares of its common stock under the 2016 Plan, the 2011 Omnibus Equity Compensation Plan (the 2011 Plan), and the 2007 Omnibus Equity Compensation Plan (the 2007 Plan and, collectively with the 2016 Plan and the 2011 Plan, the Omnibus Plans). The Omnibus Plans were submitted to and approved by the Company's shareholders. New shares of common stock will be issued for employee stock option exercises. Under the Omnibus Plans, the exercise price of each option equals the closing price of APA's common stock on the date of grant. Options granted become exercisable ratably over a three-year period and expire 10 years after granted.

The following table summarizes stock option activity for the years ended December 31, 2021, 2020, and 2019:

	2021		2020		2019	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
	(In thousands, except exercise price amounts)					
Outstanding, beginning of year	3,537	$ 72.10	4,298	$ 75.24	4,872	$ 75.95
Forfeited	—	—	(37)	44.98	(80)	34.58
Expired	(525)	119.83	(724)	92.14	(494)	88.82
Outstanding, end of year[1]	3,012	63.79	3,537	72.10	4,298	75.24
Expected to vest	—	—	150	45.77	495	49.11
Exercisable, end of year[2]	3,012	63.79	3,387	73.26	3,803	78.64

(1) As of December 31, 2021, options outstanding had a weighted average remaining contractual life of 3.1 years and no intrinsic value.

(2) As of December 31, 2021, options exercisable had a weighted average remaining contractual life of 3.1 years and no intrinsic value.

There were no options issued and no options exercised during the years ended December 31, 2021, 2020, and 2019.

Restricted Stock Units and Restricted Stock Phantom Units

The Company has restricted stock unit and restricted stock phantom unit plans for eligible employees, including officers. The value of the stock-settled restricted stock unit awards is established by the market price on the date of grant and is recorded as compensation expense ratably over the vesting terms. The restricted stock phantom unit awards represent a hypothetical interest in either the Company's common stock or in ALTM's common stock, as applicable, and, once vested, are settled in cash. Compensation expense related to the cash-settled awards is recorded as a liability and remeasured at the end of each reporting period over the applicable vesting term.

For the years ended December 31, 2021, 2020, and 2019, compensation costs charged to expense for the restricted stock units and restricted stock phantom units was $95 million, $39 million, and $104 million, respectively. As of December 31, 2021, 2020, and 2019, capitalized compensation costs for the restricted stock units and restricted stock phantom units were $15 million, $6 million, and $24 million, respectively.

The following table summarizes stock-settled restricted stock unit activity for the years ended December 31, 2021, 2020, and 2019:

	2021		2020		2019	
	Units	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value
	(In thousands, except per share amounts)					
Non-vested, beginning of year	1,552	$ 28.43	2,448	$ 46.65	3,153	$ 55.54
Granted	1,506	16.46	1,352	24.60	1,479	36.81
Vested(3)	(857)	29.13	(1,933)	48.65	(1,899)	53.99
Forfeited	(128)	19.78	(315)	30.09	(285)	45.06
Non-vested, end of year(1)(2)	2,073	19.98	1,552	28.43	2,448	46.65

(1) As of December 31, 2021, there was $14 million of total unrecognized compensation cost related to 2,073,419 unvested stock-settled restricted stock units.

(2) As of December 31, 2021, the weighted-average remaining life of unvested stock-settled restricted stock units is approximately 0.8 years.

(3) The grant date fair values of the stock-settled awards vested during 2021, 2020, and 2019 were approximately $25 million, $94 million, and $103 million, respectively.

The following table summarizes cash-settled restricted stock phantom unit activity for the years ended December 31, 2021, 2020, and 2019:

	For the Year Ended December 31,		
	2021	2020	2019
	(In thousands)		
Non-vested, beginning of year	4,423	5,384	1,818
Adjustment for ALTM reverse stock split(1)	—	(1,246)	—
Granted(2)	4,441	3,462	4,831
Vested	(2,049)	(1,618)	(616)
Forfeited	(413)	(1,559)	(649)
Non-vested, end of year(3)	6,402	4,423	5,384

(1) On June 30, 2020, ALTM executed a 1-for-20 reverse stock split of its outstanding common stock. Outstanding cash-settled awards are based on the per-share market price of ALTM stock.

(2) Restricted stock phantom units granted during 2021 and 2020 included 4,375,546 and 3,378,486 awards, respectively, based on the per-share market price of APA common stock and 65,327 and 83,239 awards, respectively, based on the per-share market price of ALTM common stock. The restricted stock phantom units granted during 2020 based on ALTM's per-share market price reflect the 1-for-20 reverse stock split described above.

(3) The outstanding liability for the unvested cash-settled restricted stock phantom units that had not been recognized as of December 31, 2021 was approximately $74 million.

In January 2022, the Company awarded 775,942 restricted stock units and 2,512,602 restricted stock phantom units based on APA's weighted-average per-share market price of $29.46 under the 2016 Plan to eligible employees. Total compensation cost for the restricted stock units and the restricted stock phantom units, absent any forfeitures, is estimated to be $23 million and $76 million, respectively, and was calculated based on the per-share fair market value of a share of the Company's common stock as of the grant date. Compensation cost will be recognized over a three-year vesting period for both plans. The phantom units will be classified as a liability and remeasured at the end of each reporting period based on the change in fair value of one share of the Company's common stock.

Also during January 2022, the Company awarded 27,643 restricted stock phantom units based on ALTM's weighted-average per-share market price of $63.63. The restricted stock phantom units represent a hypothetical interest in ALTM's common stock and, once vested, are settled in cash. Total compensation cost for these restricted stock phantom units, absent any forfeitures, is estimated to be $2 million and was calculated based on the fair market value of ALTM's common stock as of the grant date. The restricted stock phantom units will be classified as a liability and remeasured at the end of each reporting period based on the change in fair value of one share of ALTM's common stock.

Performance Program

To provide long-term incentives for the Company's employees to deliver competitive shareholder returns, the Company makes annual grants of conditional restricted stock units to eligible employees. APA has a performance program for certain eligible employees with payout for 50 percent of the shares based upon measurement of total shareholder return (TSR) of APA common stock as compared to a designated peer group during a three-year performance period. Payout for the remaining 50 percent of the shares is based on performance and financial objectives as defined in the plan. The overall results of the objectives are calculated at the end of the award's stated performance period and, if a payout is warranted, applied to the target number of restricted stock units awarded. The performance shares will immediately vest 50 percent at the end of the three-year performance period, with the remaining 50 percent vesting at the end of the following year. Grants from the performance programs outstanding at December 31, 2021, are as described below:

- In January 2017, the Company's Board of Directors approved the 2017 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial stock-settled conditional restricted stock unit awards totaling 620,885 units. A total of 1,868 restricted stock units were outstanding as of December 31, 2021. The results for the performance period yielded a payout of 54 percent of target.
- In January 2018, the Company's Board of Directors approved the 2018 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 931,049 units. A total of 97,645 phantom units were outstanding as of December 31, 2021. The results for the performance period yielded a payout of 23 percent of target.
- In January 2019, the Company's Board of Directors approved the 2019 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 1,679,832 units. A total of 1,247,706 phantom units were outstanding as of December 31, 2021. The results for the performance period yielded a payout of 100 percent of target.
- In January 2020, the Company's Board of Directors approved the 2020 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 1,687,307 units. The actual amount of phantom units awarded will be between zero and 200 percent of target. A total of 1,330,823 phantom units were outstanding as of December 31, 2021, from which a minimum of zero to a maximum of 2,661,646 phantom units could be awarded.
- In January 2021, the Company's Board of Directors approved the 2021 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 1,959,856 units. The actual amount of phantom units awarded will be between zero and 200 percent of target. A total of 1,854,736 phantom units were outstanding as of December 31, 2021, from which a minimum of zero to a maximum of 3,709,472 units could be awarded.

The fair value cost of the stock-settled awards was estimated on the date of grant and is recorded as compensation expense ratably over the applicable vesting term. The fair value of the cash-settled awards is remeasured at the end of each reporting period over the applicable vesting term. Compensation costs charged to expense under the performance programs were an expense of $57 million, a credit of $8 million, and an expense of $24 million during 2021, 2020, and 2019, respectively. Capitalized compensation costs under the performance programs were an expense of $3 million, a credit of $1 million, and an expense of $3 million during 2021, 2020, and 2019, respectively.

The following table summarizes cash-settled conditional restricted stock unit activity for the year ended December 31, 2021:

	Units
	(In thousands)
Non-vested, beginning of year	3,417
Granted	1,782
Vested	(76)
Forfeited	(240)
Expired	(352)
Non-vested, end of year[(1)]	4,531

(1) As of December 31, 2021, the outstanding liability for the unvested cash-settled conditional restricted stock units that had not been recognized was approximately $36 million.

In January 2022, the Company's board of directors approved the 2022 Performance Program, pursuant to the 2016 Plan. Payout for 50 percent of the shares is based upon measurement of TSR of APA common stock as compared to a designated peer group and the S&P 500 Index during a three-year performance period. Payout for the remaining 50 percent of the shares is based on performance and financial objectives as defined in the plan. Eligible employees received the initial cash-settled conditional phantom units totaling 1,093,034 units, with the ultimate number of phantom units to be awarded ranging from zero to a maximum of 2,186,068 units. These phantom units represent a hypothetical interest in the Company's common stock, and, once vested, are settled in cash. The TSR component of the award had a grant date fair value per award of $41.88 based on a Monte Carlo simulation. The grant date fair value per award for the remaining 50 percent was $29.46 based on the weighted-average fair market value of a share of common stock of the Company as of the grant date. These phantom units will be classified as a liability and remeasured at the end of each reporting period.

15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of accumulated other comprehensive income (loss) include the following:

	As of December 31,		
	2021	2020	2019
	(In millions)		
Share of equity method interests other comprehensive loss	$ —	$ (1)	$ (1)
Pension and postretirement benefit plan (Note 12)	22	15	17
Accumulated other comprehensive income	$ 22	$ 14	$ 16

16. MAJOR CUSTOMERS

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. During 2021, sales to EGPC and CFE International accounted for approximately 14 percent and 10 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues. During 2020, sales to EGPC and Vitol accounted for approximately 17 percent and 14 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues. During 2019, sales to BP PLC and Sinopec, and their respective affiliates, each accounted for approximately 10 percent and 11 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs production revenues.

Management does not believe that the loss of any one of these customers would have a material adverse effect on the results of operations.

17. BUSINESS SEGMENT INFORMATION

As of December 31, 2021, the Company is engaged in exploration and production (Upstream) activities across three operating segments: Egypt, North Sea, and the U.S. The Company also has active exploration and appraisal operations ongoing in Suriname, as well as interests in other international locations that may, over time, result in reportable discoveries and development opportunities. The Company's Upstream business explores for, develops, and produces natural gas, crude oil and NGLs. The midstream business is operated by Altus, which owns, develops, and operates a midstream energy asset network in the Permian Basin of West Texas. Financial information for each segment is presented below:

	Egypt[1]	North Sea	U.S.			
	Upstream			Altus Midstream	Intersegment Eliminations & Other	Total[2]
	(In millions)					
2021						
Oil revenues	$ 1,806	$ 929	$ 1,850	$ —	$ —	$ 4,585
Natural gas revenues	270	183	754	—	—	1,207
Natural gas liquids revenues	9	24	676	—	(3)	706
Oil, natural gas, and natural gas liquids production revenues	2,085	1,136	3,280	—	(3)	6,498
Purchased oil and gas sales	—	—	1,476	11	—	1,487
Midstream service affiliate revenues	—	—	—	127	(127)	—
	2,085	1,136	4,756	138	(130)	7,985
Operating Expenses:						
Lease operating expenses	469	383	391	—	(2)	1,241
Gathering, processing, and transmission	12	39	309	32	(128)	264
Purchased oil and gas costs	—	—	1,575	5	—	1,580
Taxes other than income	—	—	190	14	—	204
Exploration	63	34	28	—	30	155
Depreciation, depletion, and amortization	524	270	554	12	—	1,360
Asset retirement obligation accretion	—	79	30	4	—	113
Impairments	26	22	—	160	—	208
	1,094	827	3,077	227	(100)	5,125
Operating Income (Loss)	$ 991	$ 309	$ 1,679	$ (89)	$ (30)	2,860
Other Income (Expense):						
Gain on divestitures, net						67
Loss on previously sold Gulf of Mexico properties						(446)
Derivative instrument gain, net						94
Other						228
General and administrative						(376)
Transaction, reorganization, and separation						(22)
Financing costs, net						(514)
Income Before Income Taxes						$ 1,891
Total Assets[3]	$ 2,796	$ 2,199	$ 6,269	$ 1,698	$ 341	$ 13,303
Net Property and Equipment	$ 1,720	$ 1,646	$ 4,507	$ 187	$ 275	$ 8,335
Additions to Net Property and Equipment	$ 319	$ 159	$ 523	$ 3	$ 151	$ 1,155

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2020						
Oil revenues	$ 1,102	$ 795	$ 1,209	$ —	$ —	$ 3,106
Natural gas revenues	280	67	251	—	—	598
Natural gas liquids revenues	8	21	304	—	—	333
Oil, natural gas, and natural gas liquids production revenues	1,390	883	1,764	—	—	4,037
Purchased oil and gas sales	—	—	394	4	—	398
Midstream service affiliate revenues	—	—	—	145	(145)	—
	1,390	883	2,158	149	(145)	4,435
Operating Expenses:						
Lease operating expenses	424	305	400	—	(2)	1,127
Gathering, processing, and transmission	38	50	291	38	(143)	274
Purchased oil and gas costs	—	—	354	3	—	357
Taxes other than income	—	—	108	15	—	123
Exploration	63	28	168	—	15	274
Depreciation, depletion, and amortization	601	380	779	12	—	1,772
Asset retirement obligation accretion	—	73	32	4	—	109
Impairments	529	7	3,963	2	—	4,501
	1,655	843	6,095	74	(130)	8,537
Operating Income (Loss)	$ (265)	$ 40	$ (3,937)	$ 75	$ (15)	(4,102)
Other Income (Expense):						
Gain on divestitures, net						32
Derivative instrument losses, net						(223)
Other						64
General and administrative						(290)
Transaction, reorganization, and separation						(54)
Financing costs, net						(267)
Loss Before Income Taxes						$ (4,840)
Total Assets[3]	$ 3,003	$ 2,220	$ 5,540	$ 1,786	$ 197	$ 12,746
Net Property and Equipment	$ 1,955	$ 1,773	$ 4,760	$ 196	$ 135	$ 8,819
Additions to Net Property and Equipment	$ 454	$ 215	$ 345	$ 12	$ 136	$ 1,162

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2019						
Oil revenues	$ 1,969	$ 1,163	$ 2,098	$ —	$ —	$ 5,230
Natural gas revenues	295	90	293	—	—	678
Natural gas liquids revenues	12	23	372	—	—	407
Oil, natural gas, and natural gas liquids production revenues	2,276	1,276	2,763	—	—	6,315
Purchased oil and gas sales	—	—	176	—	—	176
Midstream service affiliate revenues	—	—	—	136	(136)	—
	2,276	1,276	2,939	136	(136)	6,491
Operating Expenses:						
Lease operating expenses	484	320	645	—	(2)	1,447
Gathering, processing, and transmission	40	45	299	56	(134)	306
Purchased oil and gas costs	—	—	142	—	—	142
Taxes other than income	—	—	194	13	—	207
Exploration	100	2	688	—	15	805
Depreciation, depletion, and amortization	708	366	1,566	40	—	2,680
Asset retirement obligation accretion	—	76	29	2	—	107
Impairments	—	—	1,648	1,301	—	2,949
	1,332	809	5,211	1,412	(121)	8,643
Operating Income (Loss)	$ 944	$ 467	$ (2,272)	$ (1,276)	$ (15)	(2,152)
Other Income (Expense):						
Gain on divestitures, net						43
Derivative instrument losses, net						(35)
Other						54
General and administrative						(406)
Transaction, reorganization, and separation						(50)
Financing costs, net						(462)
Loss Before Income Taxes						$ (3,008)
Total Assets[3]	$ 3,700	$ 2,473	$ 10,388	$ 1,479	$ 67	$ 18,107
Net Property and Equipment	$ 2,573	$ 1,956	$ 9,385	$ 206	$ 38	$ 14,158
Additions to Net Property and Equipment	$ 454	$ 183	$ 1,696	$ 308	$ 93	$ 2,734

(1) Includes revenue from non-customers for the years ended December 31, 2021, 2020, and 2019 of:

	For the Year Ended December 31,		
	2021	2020	2019
	(In millions)		
Oil	$ 420	$ 95	$ 410
Natural gas	47	14	40
Natural gas liquids	2	—	1

(2) Includes a noncontrolling interest in Egypt and Altus Midstream.

(3) Intercompany balances are excluded from total assets.

18. SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

Oil and Gas Operations

The following table sets forth revenue and direct cost information relating to the Company's oil and gas exploration and production activities. The Company has no long-term agreements to purchase oil or gas production from foreign governments or authorities.

	United States	Egypt[1]	North Sea	Other International	Total[1]
			(In millions, except per boe)		
2021					
Oil and gas production revenues	$ 3,280	$ 2,085	$ 1,136	$ —	$ 6,501
Operating cost:					
Depreciation, depletion, and amortization[2]	511	477	267	—	1,255
Asset retirement obligation accretion	30	—	79	—	109
Lease operating expenses	391	469	383	—	1,243
Gathering, processing, and transmission	309	12	39	—	360
Exploration expenses	28	63	34	30	155
Production taxes[3]	188	—	—	—	188
Income tax	383	479	134	—	996
	1,840	1,500	936	30	4,306
Results of operations	$ 1,440	$ 585	$ 200	$ (30)	$ 2,195
2020					
Oil and gas production revenues	$ 1,764	$ 1,390	$ 883	$ —	$ 4,037
Operating cost:					
Depreciation, depletion, and amortization[2]	726	540	377	—	1,643
Asset retirement obligation accretion	32	—	73	—	105
Lease operating expenses	400	424	305	—	1,129
Gathering, processing, and transmission	291	38	50	—	379
Exploration expenses	168	63	28	15	274
Impairments related to oil and gas properties	3,938	374	7	—	4,319
Production taxes[3]	106	—	—	—	106
Income tax	(818)	(22)	17	—	(823)
	4,843	1,417	857	15	7,132
Results of operations	$ (3,079)	$ (27)	$ 26	$ (15)	$ (3,095)
2019					
Oil and gas production revenues	$ 2,763	$ 2,276	$ 1,276	$ —	$ 6,315
Operating cost:					
Depreciation, depletion, and amortization[2]	1,508	641	363	—	2,512
Asset retirement obligation accretion	29	—	76	—	105
Lease operating expenses	645	484	320	—	1,449
Gathering, processing, and transmission	299	40	45	—	384
Exploration expenses	688	100	2	15	805
Impairments related to oil and gas properties	1,633	—	—	—	1,633
Production taxes[3]	191	—	—	—	191
Income tax	(468)	455	188	—	175
	4,525	1,720	994	15	7,254
Results of operations	$ (1,762)	$ 556	$ 282	$ (15)	$ (939)

(1) Includes a noncontrolling interest in Egypt.

(2) Reflects DD&A of capitalized costs of oil and gas properties and, therefore, does not agree with DD&A reflected on Note 17—Business Segment Information.

(3) Reflects only amounts directly related to oil and gas producing properties and, therefore, does not agree with taxes other than income reflected on Note 17—Business Segment Information.

Costs Incurred in Oil and Gas Property Acquisitions, Exploration, and Development Activities

	United States	Egypt[2]	North Sea	Other International	Total[2]
			(In millions)		
2021					
Acquisitions:					
Proved	$ —	$ (157)	$ —	$ —	$ (157)
Unproved	9	20	—	—	29
Exploration	6	86	39	170	301
Development	545	404	135	2	1,086
Costs incurred[1]	$ 560	$ 353	$ 174	$ 172	$ 1,259
[1] Includes capitalized interest, asset retirement costs, and Egypt modernization impacts as follows:					
Capitalized interest	$ —	$ —	$ —	$ 9	$ 9
Asset retirement costs	130	—	19	—	149
Egypt PSC modernization impacts - Proved and Unproved	—	(145)	—	—	(145)
2020					
Acquisitions:					
Proved	$ —	$ 7	$ —	$ —	$ 7
Unproved	4	—	—	—	4
Exploration	8	102	68	150	328
Development	332	378	162	—	872
Costs incurred[1]	$ 344	$ 487	$ 230	$ 150	$ 1,211
[1] Includes capitalized interest and asset retirement costs as follows:					
Capitalized interest	$ —	$ —	$ —	$ 3	$ 3
Asset retirement costs	9	—	29	—	38
2019					
Acquisitions:					
Proved	$ 3	$ 5	$ —	$ —	$ 8
Unproved	47	10	—	—	57
Exploration	162	139	62	105	468
Development	1,500	374	119	3	1,996
Costs incurred[1]	$ 1,712	$ 528	$ 181	$ 108	$ 2,529
[1] Includes capitalized interest and asset retirement costs as follows:					
Capitalized interest	$ 23	$ —	$ 5	$ 4	$ 32
Asset retirement costs	14	—	(111)	—	(97)

[2] Includes a noncontrolling interest in Egypt.

In 2021, in connection with APA's agreement to enter into a modernized PSC agreement with EGPC, as referenced in Note 1—Summary of Significant Accounting Policies, the Company recorded a reduction in proved properties totaling $165 million and an increase in unproved properties of $20 million, reflecting $247 million of incremental value due to the Company for the period between the effective date of April 1, 2021 and closing, partially offset by a $100 million signing bonus and $2 million of other post-closing adjustments.

Capitalized Costs

The following table sets forth the capitalized costs and associated accumulated depreciation, depletion, and amortization relating to the Company's oil and gas acquisition, exploration, and development activities:

	United States	Egypt(1)	North Sea	Other International	Total(1)
			(In millions)		
2021					
Proved properties	$ 18,732	$ 12,373	$ 8,954	$ —	$ 40,059
Unproved properties	319	63	33	275	690
	19,051	12,436	8,987	275	40,749
Accumulated DD&A	(14,814)	(10,767)	(7,345)	—	(32,926)
	$ 4,237	$ 1,669	$ 1,642	$ 275	$ 7,823
2020					
Proved properties	$ 20,343	$ 12,069	$ 8,805	$ —	$ 41,217
Unproved properties	348	77	42	135	602
	20,691	12,146	8,847	135	41,819
Accumulated DD&A	(16,252)	(10,290)	(7,081)	—	(33,623)
	$ 4,439	$ 1,856	$ 1,766	$ 135	$ 8,196

(1) Includes a noncontrolling interest in Egypt.

Oil and Gas Reserve Information

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, the Company 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. The Company 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.

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

	Crude Oil and Condensate			
	United States	Egypt[1]	North Sea	Total[1]
	(Thousands of barrels)			
Proved developed reserves:				
December 31, 2018	300,484	110,014	104,491	514,989
December 31, 2019	278,145	103,573	101,712	483,430
December 31, 2020	206,936	95,981	86,566	389,483
December 31, 2021	180,968	106,646	77,073	364,687
Proved undeveloped reserves:				
December 31, 2018	45,182	9,484	11,278	65,944
December 31, 2019	46,716	10,831	10,049	67,596
December 31, 2020	25,516	11,228	7,273	44,017
December 31, 2021	18,168	11,003	5,757	34,928
Total proved reserves:				
Balance December 31, 2018	345,666	119,498	115,769	580,933
Extensions, discoveries and other additions	52,297	21,039	9,017	82,353
Revisions of previous estimates	(16,446)	4,752	5,132	(6,562)
Production	(38,344)	(30,885)	(18,157)	(87,386)
Sales of minerals in-place	(18,312)	—	—	(18,312)
Balance December 31, 2019	324,861	114,404	111,761	551,026
Extensions, discoveries and other additions	17,858	17,855	5,275	40,988
Revisions of previous estimates	(69,247)	2,541	(4,756)	(71,462)
Production	(32,299)	(27,591)	(18,441)	(78,331)
Sales of minerals in-place	(8,721)	—	—	(8,721)
Balance December 31, 2020	232,452	107,209	93,839	433,500
Extensions, discoveries and other additions	17,869	13,390	2,288	33,547
Purchases of minerals in-place	126	—	—	126
Revisions of previous estimates	(4,479)	22,727	(60)	18,188
Production	(27,450)	(25,677)	(13,237)	(66,364)
Sales of minerals in-place	(19,382)	—	—	(19,382)
Balance December 31, 2021	199,136	117,649	82,830	399,615

(1) Includes proved reserves of 39 MMbbls, 36 MMbbls, 38 MMbbls, and 40 MMbbls as of December 31, 2021, 2020, 2019, and 2018, respectively, attributable to a noncontrolling interest in Egypt.

	Natural Gas Liquids			
	United States	Egypt[1]	North Sea	Total[1]
	(Thousands of barrels)			
Proved developed reserves:				
December 31, 2018	197,574	502	1,938	200,014
December 31, 2019	158,794	667	2,317	161,778
December 31, 2020	150,599	716	2,053	153,368
December 31, 2021	164,172	446	2,059	166,677
Proved undeveloped reserves:				
December 31, 2018	33,796	60	631	34,487
December 31, 2019	23,569	90	660	24,319
December 31, 2020	15,141	126	320	15,587
December 31, 2021	16,380	30	275	16,685
Total proved reserves:				
Balance December 31, 2018	231,370	562	2,569	234,501
Extensions, discoveries and other additions	41,343	27	697	42,067
Revisions of previous estimates	(32,569)	508	345	(31,716)
Production	(24,959)	(340)	(634)	(25,933)
Sales of minerals in-place	(32,822)	—	—	(32,822)
Balance December 31, 2019	182,363	757	2,977	186,097
Extensions, discoveries and other additions	11,435	97	312	11,844
Revisions of previous estimates	(469)	264	(207)	(412)
Production	(27,133)	(276)	(709)	(28,118)
Sales of minerals in-place	(456)	—	—	(456)
Balance December 31, 2020	165,740	842	2,373	168,955
Extensions, discoveries and other additions	21,055	7	81	21,143
Purchases of minerals in-place	191	—	—	191
Revisions of previous estimates	22,724	(180)	318	22,862
Production	(24,175)	(193)	(438)	(24,806)
Sales of minerals in-place	(4,983)	—	—	(4,983)
Balance December 31, 2021	180,552	476	2,334	183,362

(1) Includes proved reserves of 159 Mbbls, 281 Mbbls, 252 Mbbls, and 187 Mbbls as of December 31, 2021, 2020, 2019, and 2018, respectively, attributable to a noncontrolling interest in Egypt.

	Natural Gas			
	United States	Egypt(1)	North Sea	Total(1)
	(Millions of cubic feet)			
Proved developed reserves:				
December 31, 2018	1,626,403	476,132	95,347	2,197,882
December 31, 2019	945,938	433,382	106,329	1,485,649
December 31, 2020	1,052,756	409,035	68,159	1,529,950
December 31, 2021	1,237,461	464,826	76,155	1,778,442
Proved undeveloped reserves:				
December 31, 2018	267,090	33,006	15,804	315,900
December 31, 2019	115,040	24,704	16,604	156,348
December 31, 2020	76,504	12,572	8,341	97,417
December 31, 2021	184,441	9,899	7,124	201,464
Total proved reserves:				
Balance December 31, 2018	1,893,493	509,138	111,151	2,513,782
Extensions, discoveries and other additions	249,205	34,758	27,711	311,674
Revisions of previous estimates	(509,753)	18,570	4,015	(487,168)
Production	(233,447)	(104,380)	(19,944)	(357,771)
Sales of minerals in-place	(338,520)	—	—	(338,520)
Balance December 31, 2019	1,060,978	458,086	122,933	1,641,997
Extensions, discoveries and other additions	60,965	83,718	8,140	152,823
Revisions of previous estimates	215,166	(19,849)	(33,541)	161,776
Production	(205,594)	(100,348)	(21,032)	(326,974)
Sales of minerals in-place	(2,255)	—	—	(2,255)
Balance December 31, 2020	1,129,260	421,607	76,500	1,627,367
Extensions, discoveries and other additions	227,684	50,209	3,684	281,577
Purchases of minerals in-place	839	—	—	839
Revisions of previous estimates	279,610	99,143	17,171	395,924
Production	(192,523)	(96,234)	(14,076)	(302,833)
Sales of minerals in-place	(22,968)	—	—	(22,968)
Balance December 31, 2021	1,421,902	474,725	83,279	1,979,906

(1) Includes proved reserves of 158 Bcf, 141 Bcf, 153 Bcf, and 170 Bcf as of December 31, 2021, 2020, 2019, and 2018, respectively, attributable to a noncontrolling interest in Egypt.

	Total Equivalent Reserves			
	United States	Egypt[(1)]	North Sea	Total[(1)]
	(Thousands barrels of oil equivalent)			
Proved developed reserves:				
December 31, 2018	769,125	189,871	122,320	1,081,316
December 31, 2019	594,595	176,470	121,751	892,816
December 31, 2020	532,994	164,870	99,979	797,843
December 31, 2021	551,384	184,563	91,825	827,772
Proved undeveloped reserves:				
December 31, 2018	123,493	15,045	14,543	153,081
December 31, 2019	89,458	15,038	13,476	117,972
December 31, 2020	53,408	13,449	8,983	75,840
December 31, 2021	65,288	12,683	7,219	85,190
Total proved reserves:				
Balance December 31, 2018	892,618	204,916	136,863	1,234,397
Extensions, discoveries and other additions	135,174	26,859	14,333	176,366
Revisions of previous estimates	(133,974)	8,355	6,146	(119,473)
Production	(102,211)	(48,622)	(22,115)	(172,948)
Sales of minerals in-place	(107,554)	—	—	(107,554)
Balance December 31, 2019	684,053	191,508	135,227	1,010,788
Extensions, discoveries and other additions	39,454	31,905	6,944	78,303
Revisions of previous estimates	(33,854)	(502)	(10,554)	(44,910)
Production	(93,698)	(44,592)	(22,655)	(160,945)
Sales of minerals in-place	(9,553)	—	—	(9,553)
Balance December 31, 2020	586,402	178,319	108,962	873,683
Extensions, discoveries and other additions	76,871	21,765	2,983	101,619
Purchases of minerals in-place	457	—	—	457
Revisions of previous estimates	64,847	39,071	3,120	107,038
Production	(83,712)	(41,909)	(16,021)	(141,642)
Sales of minerals in-place	(28,193)	—	—	(28,193)
Balance December 31, 2021	616,672	197,246	99,044	912,962

(1) Includes total proved reserves of 66 MMboe, 59 MMboe, 64 MMboe, and 68 MMboe as of December 31, 2021, 2020, 2019, and 2018, respectively, attributable to a noncontrolling interest in Egypt.

During 2021, the Company added approximately 102 MMboe from extensions, discoveries, and other additions. The Company recorded 77 MMboe of exploration and development adds in the U.S., comprising 59 MMboe in the Permian Basin with the remaining 18 MMboe in the Texas Gulf Coast. The Permian Basin drilling programs targeted the Woodford, Barnett, Bone Springs, and Spraberry, while the Texas Gulf Coast focused on the Austin Chalk. International operations contributed 25 MMboe of exploration and development adds, with Egypt contributing 22 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area concession post-PSC modernization. The North Sea contributed 3 MMboe. The Company had combined upward revisions of previously estimated reserves of 107 MMboe. Upward revisions related to changes in product prices accounted for 85 MMboe. Engineering and performance upward revisions accounted for 22 MMboe, with the modernized PSC in Egypt resulting in an increase of 57 MMboe, partially offset by other downward revisions of 35 MMboe across all of the Company's geographic areas of operation. The Company also sold 28 MMboe of proved reserves associated with U.S. divestitures, primarily related to Permian Basin assets.

As previously discussed, in December 2021, the Egyptian government signed into law an agreement to modernize and consolidate a majority of the Company's Egypt PSCs. The impact of the consolidated PSC to proved reserves based on the modernized terms is an estimated increase of 53 MMboe and 4 MMboe in developed and undeveloped reserves, respectively, and approximately $750 million in discounted future net cash flows. Approximately 96 percent of the Company's Egypt reserves are now consolidated within the modernized PSC. These estimates include Sinopec's noncontrolling interest in Egypt.

During 2020, the Company added approximately 78 MMboe from extensions, discoveries, and other additions. The Company recorded 39 MMboe of exploration and development adds in the U.S., primarily in the Southern Midland Basin (26 MMboe) associated with the Wolfcamp and Spraberry drilling programs and the remainder in the Delaware Basin and Austin Chalk. The international operations contributed 39 MMboe of exploration and development adds during 2020, with Egypt contributing 32 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area and Umbarka Area concessions. The North Sea contributed 7 MMboe from drilling success, primarily in the Beryl Field. The Company had combined downward revisions of previously estimated reserves of 45 MMboe. Downward revisions related to changes in product prices accounted for 70 MMboe, engineering and performance upward revisions accounted for 27 MMboe, and downward interest revisions accounted for 2 MMboe. The Company also sold 10 MMboe of proved reserves associated with U.S. divestitures, primarily related to Eastern Shelf and Magnet Withers/Pickett Ridge.

During 2019, the Company added approximately 176 MMboe from extensions, discoveries, and other additions. The Company recorded 135 MMboe of exploration and development adds in the U.S., primarily associated with Woodford, Bone Springs, Spraberry, Barnett, and Wolfcamp drilling programs in the Permian Basin (129 MMboe) and various offset drilling activity in the Midcontinent region (6 MMboe). The Company’s international assets contributed 41 MMboe of exploration and development adds during 2019. Egypt contributed 27 MMboe from onshore exploration and appraisal activity in the Khalda Extension 2, Khalda, Khalda Extension 3, East Bahariya Extension 3, and West Kanayis concessions. The North Sea contributed 14 MMboe from drilling success in the Beryl and Forties fields. The Company had combined downward revisions of previously estimated reserves of 119 MMboe. Downward revisions related to changes in product prices accounted for 139 MMboe and engineering and performance upward revisions accounted for 20 MMboe. The Company also sold 107 MMboe of proved reserves associated with U.S. divestitures, primarily related to the sale of the Company’s Woodford-SCOOP and STACK plays and Western Anadarko Basin assets.

Approximately 12 percent of the Company’s year-end 2021 estimated proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe, or that have been completed but not yet produced, or zones that have been produced in the past, but are not now producing because of mechanical reasons. These reserves are considered to be a lower tier of reserves than producing reserves because they are frequently based on volumetric calculations rather than performance data. Future production associated with behind pipe reserves is scheduled to follow depletion of the currently producing zones in the same wellbores. Additional capital may have to be spent to access these reserves. The capital and economic impact of production timing are reflected in this Note 18, under “Future Net Cash Flows.”

Future Net Cash Flows

Future cash inflows as of December 31, 2021, 2020, and 2019 were calculated using an unweighted arithmetic average of oil and gas prices in effect on the first day of each month in the respective year, except where prices are defined by contractual arrangements. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Future development costs include abandonment and dismantlement costs.

The following table sets forth unaudited information concerning future net cash flows for proved oil and gas reserves, net of income tax expense. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and gas producing activities. This information does not purport to present the fair market value of the Company's oil and gas assets, but does present a standardized disclosure concerning possible future net cash flows that would result under the assumptions used.

	United States	Egypt[1]	North Sea	Total[1]
	(In millions)			
2021				
Cash inflows	$ 22,852	$ 9,337	$ 6,832	$ 39,021
Production costs	(8,323)	(1,712)	(2,343)	(12,378)
Development costs	(1,632)	(1,402)	(2,533)	(5,567)
Income tax expense	(134)	(1,887)	(768)	(2,789)
Net cash flows	12,763	4,336	1,188	18,287
10 percent discount rate	(5,294)	(983)	350	(5,927)
Discounted future net cash flows[2]	$ 7,469	$ 3,353	$ 1,538	$ 12,360
2020				
Cash inflows	$ 12,537	$ 5,560	$ 4,122	$ 22,219
Production costs	(6,244)	(1,704)	(2,388)	(10,336)
Development costs	(1,555)	(633)	(2,448)	(4,636)
Income tax expense	—	(1,096)	316	(780)
Net cash flows	4,738	2,127	(398)	6,467
10 percent discount rate	(1,829)	(437)	1,111	(1,155)
Discounted future net cash flows[2]	$ 2,909	$ 1,690	$ 713	$ 5,312
2019				
Cash inflows	$ 21,694	$ 8,306	$ 7,454	$ 37,454
Production costs	(10,642)	(1,847)	(2,730)	(15,219)
Development costs	(1,740)	(707)	(2,651)	(5,098)
Income tax expense	(27)	(1,930)	(784)	(2,741)
Net cash flows	9,285	3,822	1,289	14,396
10 percent discount rate	(4,003)	(808)	297	(4,514)
Discounted future net cash flows[2]	$ 5,282	$ 3,014	$ 1,586	$ 9,882

(1) Includes discounted future net cash flows of approximately $1.1 billion, $563 million, and $1.0 billion as of December 31, 2021, 2020, and 2019, respectively, attributable to a noncontrolling interest in Egypt.

(2) Estimated future net cash flows before income tax expense, discounted at 10 percent per annum, totaled approximately $15.3 billion, $7.1 billion, and $12.4 billion as of December 31, 2021, 2020, and 2019, respectively.

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

	For the Year Ended December 31,		
	2021	2020	2019
		(In millions)	
Sales, net of production costs	$ (4,707)	$ (2,422)	$ (4,291)
Net change in prices and production costs	9,376	(5,753)	(3,034)
Discoveries and improved recovery, net of related costs	1,749	751	2,042
Change in future development costs	(839)	20	(75)
Previously estimated development costs incurred during the period	545	576	983
Revision of quantities	1,983	(418)	(741)
Purchases of minerals in-place	1	—	—
Accretion of discount	626	1,236	1,693
Change in income taxes	(1,583)	1,533	720
Sales of minerals in-place	(116)	(104)	(817)
Change in production rates and other	13	11	(319)
	$ 7,048	$ (4,570)	$ (3,839)

Exhibit 10.41

SCHEDULE A

APA Corporation

Restricted Stock Unit Award Agreement

GRANT NOTICE

Recipient Name:	[Name]
Company:	APA Corporation
Notice:	A summary of the terms of your grant of Restricted Stock Units ("RSUs") is set out in this notice (the "Grant Notice") but subject always to the terms of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan") and the Restricted Stock Unit Award Agreement (the "Agreement"). In the event of any inconsistency between the terms of this Grant Notice, the terms of the Plan and the Agreement, the terms of the Plan and the Agreement shall prevail. The Grant is a Cash-Based Award under Section 10 of the Plan and is subject to the provisions of the Plan governing RSUs. You have been awarded a grant of Altus Midstream Company RSUs in accordance with the terms of the Plan and the Agreement. Details of the RSUs which you are entitled to receive is provided to you in this Grant Notice and maintained on your account at netbenefits.fidelity.com.
Type of Award:	Restricted Stock Unit(s)
Restricted Stock Unit:	A Restricted Stock Unit ("RSU") under this Agreement means the right granted to the Recipient to receive the cash equivalent of one share of Stock (as defined below) for each RSU at the end of the specified Vesting Period.
Stock:	The $0.0001 par value Class A common stock of Altus Midstream Company.
Grant:	A Grant related to ______ Restricted Stock Units.
Grant Date:	[Date]
Conditions:	The Recipient may elect, at the time of the grant, to have his or her RSUs deferred into the Deferred Delivery Plan (the "DDP") when the RSUs vest, in which case the Recipient will receive the value of

the RSUs in cash at the times specified pursuant to the DDP. For RSUs that are not deferred, once the RSU vests, the Recipient shall be paid the value of his or her RSUs in cash (net of cash withheld for applicable tax withholdings).

Vesting Period: RSUs granted shall vest (i.e., restrictions shall lapse) in accordance with the following schedule (the "Vesting Period"), provided that the Recipient remains employed as an Eligible Person as of such vesting date:

First day of the month following the first anniversary of the Grant Date – 1/3 vested.

Second anniversary of the Grant Date – an additional 1/3 vested.

Third anniversary of the Grant Date – an additional 1/3 vested.

Notwithstanding the foregoing, if the Recipient's termination of employment from the Company and the Affiliates occurs by reason of his or her Retirement, the Recipient shall be deemed to continue to be employed as an Eligible Person for purposes of this Grant and shall continue to vest with respect to a specified percentage of RSUs over the Vesting Period set forth above provided that the Recipient meets the Retirement Conditions set forth in section 5 of the Agreement.

Upon vesting (other than upon death or Disability), the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had elected to defer such RSUs into the DDP, in which case the applicable amount of cash shall be paid to the DDP on the vesting date and paid out according to the provisions of the DDP.

Vesting is accelerated to 100% upon the Recipient's death or cessation of employment by reason of Disability while an Eligible Person (or, only in the case of death, while treated as an Eligible Person following Retirement as described above) during the Vesting Period. Upon vesting, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable, in accordance with the terms of the Plan and this Agreement. The Recipient can name a beneficiary on a form approved by the Committee.

Vesting is accelerated to 100% upon the Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control that occurs during the Vesting Period.

With respect to a Recipient who continues to vest following his or her termination due to Retirement, vesting is accelerated to 100% upon a Change of Control that occurs during the Vesting Period and on or after such termination by reason of Retirement. With respect to a Recipient who terminates employment by reason of Retirement after a Change of Control, vesting is accelerated to 100% upon the Recipient's termination of employment by reason of Retirement. Unless expressly otherwise provided in the Agreement with respect to Retirement and Change of Control, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had elected to defer such RSUs into the DDP, in which case the applicable amount of cash shall be paid to the DDP on the vesting date and paid out according to the provisions of the DDP.

Withholding: The Company and the Recipient will comply with all federal and state laws and regulations respecting the required withholding, deposit, and payment of any income, employment, or other taxes relating to the Grant.

Dividends: The Company will credit each of the Recipient's RSUs with Dividend Equivalents. For purposes of this Grant, a Dividend Equivalent is an amount equal to the cash dividend payable per share of Stock multiplied by the number of shares of Stock then underlying such outstanding RSUs. Such amount will be credited to a book entry account on Recipient's behalf at the time Altus Midstream Company pays any cash dividend on its Stock. The Recipient's rights in any such Dividend Equivalents will vest at the same time as, and only to the extent that, the underlying RSUs vest and will be distributed at the same time in cash (subject to applicable withholdings), and only to the extent, as the related RSUs are to be distributed to the Recipient as provided in the Agreement and to which such Dividend Equivalents apply.

Acceptance: Please complete the on-line grant acceptance as promptly as possible to accept or reject your Grant. You can access this through your account at netbenefits.fidelity.com. By accepting your Grant, you will have agreed to the terms and conditions set forth in the Agreement, including, but not limited to, the non-compete and non-disparagement provisions set forth in sections 5 and 6 of the Agreement, and the terms and conditions of the Plan. If you do not accept your Grant, your RSUs will not vest and you will be unable to receive your RSUs.

APA Corporation

Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the "Agreement") relating to a grant of Restricted Stock Units is a Cash-Based Award under Section 10 of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan") (the "Grant"), dated as of the Grant Date set forth in the Notice of Award under the Agreement attached as Schedule A hereto (the "Grant Notice"), and is made between APA Corporation (together with its Affiliates, the "Company") and each Recipient. The Grant Notice is included in and made part of this Agreement.

In this Agreement and each Grant Notice, unless the context otherwise requires, words and expressions shall have the meanings given to them in the Plan except as herein defined.

Definitions

"409A Change of Control" means a Change of Control that constitutes, with respect to APA Corporation, a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation" within the meaning of Section 409A(a)(2)(A)(v) of the Internal Revenue Code of 1986, as amended (the "Code") and Treasury Regulations Section 1.409A-3(i)(5).

"Disability" or "Disabled" means the Recipient is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. Recipient agrees that a final and binding determination of "Disability" will be made by the Company's representative under the Company's group long-term disability plan or any successor thereto or, if there is no such representative and there is a dispute as to the determination of "Disability," it will be decided in a court of law in Harris County, Texas.

"Grant Notice" means the separate notice given to each Recipient specifying the number of RSUs granted to the Recipient (the "Grant").

"Fair Market Value" means the fair market value of a share of the Stock as determined by the Committee by the reasonable application of such reasonable valuation method, consistently applied, as the Committee deems appropriate; provided, however, that if the Committee has not made such determination, such fair market value shall be the per share closing price of the Stock as reported on Nasdaq or on such other exchange or electronic trading system as, on the date in question, reports the largest number of traded shares of stock; provided further, however, that if there are no Stock transactions on such date, the Fair Market Value shall be determined as of the immediately preceding date on which there were Stock transactions.

"Involuntary Termination" means the termination of employment of the Recipient by the Company or its successor or an applicable Affiliate for any reason on or after a Change of Control; provided, that the termination does not result from an act of the Recipient that (i) constitutes common-law fraud, a felony, or a gross malfeasance of duty and (ii) is materially detrimental to the best interests of the Company or its successor; provided that, notwithstanding anything else in this Agreement to the contrary, an Involuntary Termination shall not be deemed to occur solely because a Recipient transfers employment from the Company to an Affiliate, from an Affiliate to the Company, or from one Affiliate to another Affiliate.

"Payout Amount" means the vested portion of the Grant expressed as an amount of cash equal to the Fair Market Value of the shares of Stock underlying the RSUs and related Dividend Equivalents.

"Recipient" means an Eligible Person designated by the Committee at the Grant Date to receive one or more Grants under the Plan.

"Retirement" means, with respect to a Recipient and for purposes of this Agreement, the date the Recipient terminates employment with the Company after attaining (i) age 55 and (ii) a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto.

"Years of Service" means the total number of months from the Recipient's date of hire by the Company to the date of termination of employment, plus any months required to be recognized under an appropriate acquisition agreement, divided by 12.

"Voluntary Termination with Cause" occurs upon a Recipient's separation from service of his or her own volition and one or more of the following conditions occurs without the Recipient's consent on or after a Change of Control:

(a) There is a material diminution in the Recipient's base compensation, compared to his or her rate of base compensation on the date of the Change of Control.

(b) There is a material diminution in the Recipient's authority, duties or responsibilities.

(c) There is a material diminution in the authority, duties or responsibilities of the Recipient's supervisor, such as a requirement that the Recipient (or his or her supervisor) report to a corporate officer or employee instead of reporting directly to the board of directors.

(d) There is a material diminution in the budget over which the Recipient retains authority.

(e) There is a material change in the geographic location at which the Recipient must perform his or her service, including, for example the assignment of the Recipient to a regular workplace that is more than 50 miles from his or her regular workplace on the date of the Change of Control.

The Recipient must notify the Company of the existence of one or more adverse conditions specified in clauses (a) through (e) above within 90 days of the initial existence of the adverse condition. The notice must be provided in writing to the Company or its successor, attention: Vice President, Human Resources. The notice may be provided by personal delivery or it may be sent by email, inter-office mail, regular mail (whether or not certified), fax, or any similar method. The Company's Vice President, Human Resources, or his/her delegate shall acknowledge receipt of the notice within 5 business days; the acknowledgement shall be sent to the Recipient by certified mail. Notwithstanding the foregoing provisions of this definition, if the Company remedies the adverse condition within 30 days of being notified of the adverse condition, no Voluntary Termination with Cause shall occur.

Terms

1. Grant of RSUs. Subject to the provisions of this Agreement and the provisions of the Plan and Grant Notice, the Company shall grant to the Recipient, pursuant to the Plan, a right to receive the number of RSUs set forth in the Recipient's Grant Notice. The Grant shall give the Recipient the right, upon vesting, to receive an amount in cash equal to the Fair Market Value of an equal number of shares of $0.0001 par value Class A common stock of Altus Midstream Company ("Stock") to that of the number of RSUs set forth in the Recipient's Grant Notice. At the time of the Grant, the Recipient may elect to defer all or any portion of the RSUs in the Deferred Delivery Plan (the "DDP").

2. Vesting and Payment of Cash. Subject to the provisions of sections 3 and 4 of this Agreement, the entitlement to receive an amount of cash equal to the Fair Market Value of the number of shares of Stock pursuant to the RSUs comprising the Grant Amount shall vest in accordance with the schedule set forth in the Grant Notice (the "Vesting Period"); provided that the Recipient remains employed as an Eligible Person on such applicable vesting dates. Unless the Recipient elected to defer the RSU into the DDP, such cash, subject to applicable withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date (other than upon death or Disability). To the extent that the Recipient elected to defer the RSUs into the DDP and sections 3 and 4 do not apply, when the RSUs vest, an amount of cash equal to the Fair Market Value of the number of shares of Stock that have vested pursuant to the RSUs comprising the Grant Amount shall be paid to the DDP and paid thereafter to the Recipient as specified under the terms of the DDP.

3. Termination of Employment, Retirement, Death, or Disability. Except as set forth below in this section 3 and in section 4 of this Agreement, each Grant shall be subject to the condition that the Recipient has remained an Eligible Person from the award of the Grant of RSUs until the applicable vesting date as follows:

(a) If the Recipient voluntarily leaves the employment of the Company (other than for reason of Retirement), or if the employment of the Recipient is terminated by the Company for any reason or no reason, any RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall thereafter be void and forfeited for all purposes.

(b) If the Recipient leaves the employment of the Company by reason of Retirement, the RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall continue to vest following the Recipient's termination of employment by reason of Retirement as if the Recipient remained an Eligible Person in the employ of the Company, provided that such Recipient shall be entitled to continue vesting only if such Recipient satisfies the Retirement Conditions set forth in section 5 below (except in the case of death) and only with respect to the specified percentage of such unvested RSUs set forth in Exhibit "A" for a certain combination of age and Years of Service attained by the Recipient as of the Recipient's Retirement under the Matrix set forth in Exhibit "A".

(c) A Recipient shall become 100% vested in all RSUs under the Grant Notice on the date the Recipient dies while employed by the Company regardless whether Recipient has accepted the Grant, or on the date the Recipient is no longer employed by the Company by reason of Disability, or, only in the case of death, while continuing to vest pursuant to section 3(b) of this Agreement. Payment shall be made as soon as administratively practicable, but in no event (i) in the case of death, shall the payment occur later than the last day of the calendar year following the calendar year in which such death occurs or (ii) in the case of cessation of employment by reason of Disability, shall the payment occur later than thirty (30) days following the date the Recipient is determined to be Disabled and is no longer employed by the Company. If clause (ii) is applicable and the period from the date on which the Recipient is determined to be Disabled and is no longer employed by the Company to the date under clause (ii) spans two consecutive calendar years, payment shall be made in the second calendar year of such consecutive calendar years. Such payment shall be made to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable. Each Recipient may designate a beneficiary on a form approved by the Committee.

4. Change of Control. Pursuant to Section 13.1(c)(iii) and (d) of the Plan, the following provisions of this section 4 of the Agreement shall supersede Sections 13.1(a), (b) and (c) of the Plan. Without any further action by the Committee or the Board, in the event of a Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of his or her Involuntary Termination or Voluntary Termination with Cause. Subject to section 11(b) of this Agreement, payment shall occur within thirty (30) days following the date of such Involuntary Termination or Voluntary Termination with Cause, subject to required tax withholding. Further, in the event of a Change of Control following the Recipient's termination of employment by reason of Retirement while the Recipient is continuing to vest in the RSUs pursuant to section 3(b) of this Agreement, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of the Change of Control (including those excluded by the specified percentage set forth in Exhibit "A"). Subject to section 11(b) of this Agreement, the Recipient, if the Recipient terminates employment on account of Retirement prior to the occurrence of a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs within thirty (30) days of the date of a 409A Change of Control, or if the Change of Control is not a 409A Change of Control, on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding. Further still, in the event of a Change of Control prior to the Recipient's termination of employment by reason of Retirement during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date the Recipient terminates employment by reason of Retirement (including those excluded by the specified percentage set forth in Exhibit "A"). For the purpose of vesting as set forth in the prior sentence, a Recipient's Involuntary Termination or Voluntary Termination with Cause after a Change of Control shall be deemed a termination by reason of Retirement. Subject to section 11(b) of this Agreement, the Recipient, who terminates

employment by reason of Retirement after a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding.

5. Conditions to Post-Retirement Vesting. If the Recipient has attained age 55 and a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto and terminates employment with the Company and the Affiliates by reason of Retirement, it is agreed by the Company and the Recipient that:

(a) subject to the provisions of this section 5(a) and sections 5(b) and 5(c), such Recipient shall continue to vest in the specified percentage of unvested RSUs set forth in Exhibit "A", for the combination of age and Years of Service attained by such Recipient as of his or her Retirement under the Matrix set forth in Exhibit "A", following the date of his or her termination by reason of Retirement as if the Recipient continued in employment as an Eligible Person provided that the Grant Date of the unvested RSUs is prior to such termination date in an amount of time which allows the Recipient to provide the written notice as follows and the Recipient has provided advance written notice not before three (3) months following the Grant Date and not less than the number of months prior to such termination date as set forth in the Schedule below to APA Corporation's Vice President, Human Resources, or his or her delegate, and to his or her direct manager, regarding the Recipient's intent to terminate employment for reason of Retirement; provided, however, a Recipient who is at least age 55 and attained the necessary combination of age and Years of Service under the Matrix set forth in Exhibit "A" for Retirement need not provide such advance written notice of his or her intent to terminate employment by reason of Retirement if the Company elects to require such Recipient to, or (as part of a reduction in force or otherwise in writing in exchange for a written release) offers such Recipient the opportunity to, terminate employment with the Company by reason of Retirement:

Age	Advance Written Notice
65 or older	3 months
between (and including) 55 and 64	6 months

; and it is further agreed that

(b) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the continuing Vesting Period after Retirement (the "Continued Vesting Period"), refrain from becoming employed by, or consulting with, or becoming substantially involved in the business of, any business that competes with the Company or its Affiliate in the business of exploration or production of oil or natural gas wherever from time to time conducted throughout the world (a "Competitive Business") and Recipient shall provide to the Company, upon Company's request, (x) a written certification, in a form provided by or satisfactory to the Company, as to Recipient's compliance with the forgoing conditions and/or (y) his/her U.S. Individual Income Tax Return for any return filed by the Recipient which relates to any time during the Continued Vesting Period to allow the Company to verify that Recipient has complied with the foregoing conditions; provided, that the Recipient may purchase and hold for investment purposes less than five percent (5%) of the shares of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system, and provided further, that the Recipient may provide services solely as a director of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system if, during the Continued Vesting Period, (i) the Recipient only attends board and board committee meetings, votes on recommendations of management, and discharges his/her fiduciary obligations under the law and (ii) the Recipient is not involved in, and does not advise or consult on, the marketing, government relations, customer relations, or the day-to-day management, supervision, or operations of such Competitive Business; and it is further agreed that

(c) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the Continued Vesting Period, refrain from making, or causing or assisting any other person to make, any oral or written communication to any third party about the Company, any Affiliate and/or any of the employees, officers or directors of the Company or any Affiliate which impugns or attacks, or is otherwise critical of, the reputation, business or character of such entity or person; or that discloses private or confidential information about their business affairs; or that constitutes an intrusion into their seclusion or private lives; or that gives rise to unreasonable publicity about their private lives; or that places them in a false light before the public; or that constitutes a misappropriation of their name or likeness.

Notwithstanding the foregoing provisions of this section 5 of the Agreement, (i) in the event that the Recipient fails to satisfy any of the conditions set forth in sections 5(a), (b) and (c) above, the Recipient shall not be entitled to vest in any unvested RSUs after the date of Retirement and the unvested RSUs subject to this Agreement shall be forfeited and (ii) the Recipient shall not have any right to continue to vest upon Retirement in any future awards granted under the Plan once the Recipient provides the notice of Retirement as set forth in section 5(a) above.

6. Prohibited Activity. In consideration for this Grant and except as permitted under section 5(b) above, the Recipient agrees not to engage in any "Prohibited Activity" while employed by the Company or within three years after the date of the Recipient's termination of employment. A "Prohibited Activity" will be deemed to have occurred, as determined by the Committee in its sole and absolute discretion, if the Recipient (i) divulges any non-public, confidential or proprietary information of the Company, but excluding information that (a) becomes generally available to the public other than as a result of the Recipient's public use, disclosure, or fault, or (b) becomes available to the Recipient on a non-confidential basis after the Recipient's employment termination date from a source other than the Company prior to the public use or disclosure by the Recipient, provided that such source is not bound by a confidentiality agreement or otherwise prohibited from transmitting the information by contractual, legal or fiduciary obligation; (ii) directly or indirectly, consults with or becomes affiliated with, participate or engage in, or becomes employed by any business that is competitive with the Company, wherever from time to time conducted throughout the world, including situations where the Recipient solicits or participates in or assists in any way in the solicitation or recruitment, directly or indirectly, of any employees of the Company; or (iii) engages in publishing any oral or written statements about the Company, and/or any of its directors, officers, or employees that are disparaging, slanderous, libelous, or defamatory; or that disclose private or confidential information about their business affairs; or that constitute an intrusion into their seclusion or private lives; or that give rise to unreasonable publicity about their private lives; or that place them in a false light before the public; or that constitute a misappropriation of their name or likeness.

7. Payment and Tax Withholding. Upon receipt of any entitlement to cash under this Agreement and, if applicable, upon the Recipient's attainment of eligibility to terminate employment by reason of Retirement pursuant to section 3(b), the Recipient shall make appropriate arrangements with the Company to provide for the amount of minimum tax and social security withholding, if any, required by law, including without limitation Sections 3102 and 3402 or any successor section(s) of the Internal Revenue Code and applicable state and local income and other tax laws. The payment of a Payout Amount shall be based on the Fair Market Value of the shares of Stock on the applicable date of vesting to which such tax withholding relates. Where appropriate, cash shall be withheld by the Company to satisfy applicable tax withholding requirements rather than paid directly to the Recipient.

8. Non-Transferability of Grant. A Grant shall not be transferable otherwise than by testamentary will or the laws of descent and distribution, or in accordance with a valid beneficiary designation on a form approved by the Committee, subject to the conditions and exceptions set forth in Section 15.2 of the Plan.

9. No Right to Continued Employment. Neither the RSUs or the cash payment pursuant to a Grant nor any terms contained in this Agreement shall confer upon the Recipient any express or implied right to be retained in the employment or service of the Company for any period, nor restrict in any way the right of the Company, which right is hereby expressly reserved, to terminate the Recipient's employment or service at any time for any reason or no reason. The Recipient acknowledges and agrees that any right to receive RSUs or cash pursuant to a Grant is earned only by continuing as an employee of the Company at the will of the Company, or satisfaction of any other applicable terms and conditions contained in the Plan and this Agreement, and not through the act of being hired, being granted the Grant, or acquiring RSUs or cash pursuant to the Grant hereunder.

10. The Plan. In consideration for this Grant, the Recipient agrees to comply with the terms of the Plan and this Agreement. This Agreement is subject to all the terms, provisions and conditions of the Plan, which are incorporated herein by reference, and to such regulations as may from time to time be adopted by the Committee. The Grant is a Cash-Based Award under Section 10 of the Plan and is subject to the provisions of the Plan governing RSUs. Unless defined herein, capitalized terms are used herein as defined in the Plan. In the event of any conflict between the provisions of the Plan and this Agreement, the provisions of the Plan shall control, and this Agreement shall be deemed to be modified accordingly. The Plan and the prospectus describing the Plan can be found on the Company's HR intranet and the Plan document can be found on Fidelity's website (netbenefits.fidelity.com). A paper copy of the Plan and the prospectus shall be provided to the recipient upon the Recipient's written request to the Company at 2000 Post Oak Blvd., Suite 100, Houston, Texas 77056-4400, Attention: Corporate Secretary.

11. Compliance with Laws and Regulations.

(a) The Grant and any obligation of the Company to deliver RSUs and cash hereunder shall be subject in all respects to (i) all applicable laws, rules and regulations and (ii) any registration, qualification, approvals or other requirements imposed by any government or regulatory agency or body which the Committee shall, in its discretion, determine to be necessary or applicable.

(b) This Grant is intended to comply with, or be exempt from, the applicable requirements of Section 409A of the Code and the rules and regulations issued thereunder and shall be administered accordingly. Notwithstanding anything in this Agreement to the contrary, if the RSUs constitute "deferred compensation" under Section 409A of the Code and any RSUs become payable pursuant to the Recipient's termination of employment, settlement of the RSUs shall be delayed for a period of six months after the Recipient's termination of employment if the Recipient is a "specified employee" as defined under Code Section 409A(a)(2)(B)(i) and if required pursuant to Section 409A of the Code. If settlement of the RSU is delayed, the RSUs shall be settled on the first day of the first calendar month following the end of the six-month delay period. If the Recipient dies during the six-month delay, the RSUs shall be settled and paid to the Recipient's designated beneficiary, legal representatives, heirs or legatees, as applicable, as soon as practicable after the date of death. Notwithstanding any provisions to the contrary herein, payments made with respect to this Grant may only be made in a manner and upon an event permitted by Section 409A of the Code, and all payments to be made upon a termination of employment hereunder may only be made upon a "separation from service", as such term is defined in Section 11.1 of the Plan. Recipient shall not have any right to determine a date of payment of any amount under this Agreement. This Agreement may be amended without the consent of the Recipient in any respect deemed by the Board or the Committee to be necessary in order to preserve compliance with Section 409A of the Code. If the Grant and this Agreement is subject to Section 409A of the Code and the rules and regulations issued thereunder, then the vesting date shall be the "designated payment date" or "specified date" under Treasury Regulation 1.409A-3(d).

12. Notices. Unless otherwise provided in this Agreement, all notices by the Recipient or the Recipient's assignees shall be addressed to the Administrative Agent, Fidelity, through the Recipient's account at netbenefits.fidelity.com, or such other address as the Company may from time to time specify. All notices to the Recipient shall be addressed to the Recipient at the Recipient's address in the Company's records.

13. Other Plans. The Recipient acknowledges that any income derived from the Grant shall not affect the Recipient's participation in, or benefits under, any other benefit plan or other contract or arrangement maintained by the Company or any Affiliate.

14. Terms of Employment. The Plan is a discretionary plan. The Recipient hereby acknowledges that neither the Plan nor this Agreement forms part of the Recipient's terms of employment and nothing in the Plan may be construed as imposing on the Company or any Affiliate a contractual obligation to offer participation in the Plan to any employee of the Company or any Affiliate. The Company or any Affiliate is under no obligation to make further Grants to any Recipient under the Plan. The Recipient hereby acknowledges that if the Recipient ceases to be an employee of the Company or any Affiliate for any reason or no reason, the Recipient shall not be entitled by way of compensation for loss of office or otherwise howsoever to any sum.

15. Data Protection. By accepting this Agreement (whether by electronic means or otherwise), the Recipient hereby consents to the holding and processing of personal data provided

by the Recipient to the Company for all purposes necessary for the operation of the Plan. These include, but are not limited to:

(a) administering and maintaining Recipient records;

(b) providing information to any registrars, brokers or third party administrators of the Plan; and

(c) providing information to future purchasers of the Company or the business in which the Recipient works.

16. Severability. If any provision of this Agreement is held invalid or unenforceable, the remainder of this Agreement shall nevertheless remain in full force and effect, and if any provision is held invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances, to the fullest extent permitted by law.

*****

Exhibit "A"

Apache Corporation
Retirement Matrix

Age at Retirement	Points (Age at Retirement + Years of Service)																				
	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%
69	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
68	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%
67	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
66	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
65	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
64	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
63	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
62	0%	0%	0%	0%	0%	0%	0%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
61	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
60	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
59	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
58	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
57	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
56	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
55	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%

0%
50%
75%
100%

Exhibit 10.42

SCHEDULE A

APA Corporation

Restricted Stock Unit Award Agreement

GRANT NOTICE

Recipient Name:	[Name]
Company:	APA Corporation
Notice:	A summary of the terms of your grant of Restricted Stock Units ("RSUs") is set out in this notice (the "Grant Notice") but subject always to the terms of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan") and the Restricted Stock Unit Award Agreement (the "Agreement"). In the event of any inconsistency between the terms of this Grant Notice, the terms of the Plan and the Agreement, the terms of the Plan and the Agreement shall prevail. The Grant is a Cash-Based Award under Section 10 of the Plan and is subject to the provisions of the Plan governing RSUs. You have been awarded a grant of APA Corporation RSUs in accordance with the terms of the Plan and the Agreement. Details of the RSUs which you are entitled to receive is provided to you in this Grant Notice and maintained on your account at netbenefits.fidelity.com.
Type of Award:	Restricted Stock Unit(s)
Restricted Stock Unit:	A Restricted Stock Unit ("RSU") as defined in the Plan and meaning the right granted to the Recipient to receive one share of Stock or the cash equivalent thereof for each RSU at the end of the specified Vesting Period.
Stock:	The $0.625 par value common stock of the Company or as otherwise defined in the Plan.
Grant:	A Grant related to ______ Restricted Stock Units.
Grant Date:	[Date]
Conditions:	The Recipient may elect, at the time of the grant, to have his or her RSUs deferred into the Deferred Delivery Plan (the "DDP") when

the RSUs vest, in which case the Recipient will receive the value of the RSUs in cash at the times specified pursuant to the DDP. For RSUs that are not deferred, once the RSU vests, the Recipient shall be paid the value of his or her RSUs in cash (net of cash withheld for applicable tax withholdings).

Vesting Period:

RSUs granted shall vest (i.e., restrictions shall lapse) in accordance with the following schedule (the "Vesting Period"), provided that the Recipient remains employed as an Eligible Person as of such vesting date:

First day of the month following the first anniversary of the Grant Date – 1/3 vested.

Second anniversary of the Grant Date – an additional 1/3 vested.

Third anniversary of the Grant Date – an additional 1/3 vested.

Notwithstanding the foregoing, if the Recipient's termination of employment from the Company and the Affiliates occurs by reason of his or her Retirement, the Recipient shall be deemed to continue to be employed as an Eligible Person for purposes of this Grant and shall continue to vest with respect to a specified percentage of RSUs over the Vesting Period set forth above provided that the Recipient meets the Retirement Conditions set forth in section 5 of the Agreement.

Upon vesting (other than upon death or Disability), the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had elected to defer such RSUs into the DDP, in which case the applicable amount of cash shall be paid to the DDP on the vesting date and paid out according to the provisions of the DDP.

Vesting is accelerated to 100% upon the Recipient's death or cessation of employment by reason of Disability while an Eligible Person (or, only in the case of death, while treated as an Eligible Person following Retirement as described above) during the Vesting Period. Upon vesting, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable, in accordance with the terms of the Plan and this Agreement. The Recipient can name a beneficiary on a form approved by the Committee.

Vesting is accelerated to 100% upon the Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control that occurs during the Vesting Period. With respect to a Recipient who continues to vest following his or her termination due to Retirement, vesting is accelerated to 100% upon a Change of Control that occurs during the Vesting Period and on or after such termination by reason of Retirement. With respect to a Recipient who terminates employment by reason of Retirement after a Change of Control, vesting is accelerated to 100% upon the Recipient's termination of employment by reason of Retirement. Unless expressly otherwise provided in the Agreement with respect to Retirement and Change of Control, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had elected to defer such RSUs into the DDP, in which case the applicable amount of cash shall be paid to the DDP on the vesting date and paid out according to the provisions of the DDP.

Withholding: The Company and the Recipient will comply with all federal and state laws and regulations respecting the required withholding, deposit, and payment of any income, employment, or other taxes relating to the Grant.

Dividends: The Company will credit each of the Recipient's RSUs with Dividend Equivalents. For purposes of this Grant, a Dividend Equivalent is an amount equal to the cash dividend payable per share of Stock multiplied by the number of shares of Stock then underlying such outstanding RSUs. Such amount will be credited to a book entry account on Recipient's behalf at the time the Company pays any cash dividend on its Stock. The Recipient's rights in any such Dividend Equivalents will vest at the same time as, and only to the extent that, the underlying RSUs vest and will be distributed at the same time in cash (subject to applicable withholdings), and only to the extent, as the related RSUs are to be distributed to the Recipient as provided in the Agreement and to which such Dividend Equivalents apply.

Acceptance: Please complete the on-line grant acceptance as promptly as possible to accept or reject your Grant. You can access this through your account at netbenefits.fidelity.com. By accepting your Grant, you will have agreed to the terms and conditions set forth in the Agreement, including, but not limited to, the non-compete and non-disparagement provisions set forth in sections 5 and 6 of the Agreement, and the terms and conditions of the Plan. If you do not accept your Grant, your RSUs will not vest and you will be unable to receive your RSUs.

APA Corporation

Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the "Agreement") relating to a grant of Restricted Stock Units (as defined in the definition section of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan")) (the "Grant"), dated as of the Grant Date set forth in the Notice of Award under the Agreement attached as Schedule A hereto (the "Grant Notice"), is made between APA Corporation (together with its Affiliates, the "Company") and each Recipient. The Grant Notice is included in and made part of this Agreement.

In this Agreement and each Grant Notice, unless the context otherwise requires, words and expressions shall have the meanings given to them in the Plan except as herein defined.

Definitions

"409A Change of Control" means a Change of Control that constitutes, with respect to APA Corporation, a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation" within the meaning of Section 409A(a)(2)(A)(v) of the Internal Revenue Code of 1986, as amended (the "Code") and Treasury Regulations Section 1.409A-3(i)(5).

"Disability" or "Disabled" means the Recipient is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. Recipient agrees that a final and binding determination of "Disability" will be made by the Company's representative under the Company's group long-term disability plan or any successor thereto or, if there is no such representative and there is a dispute as to the determination of "Disability," it will be decided in a court of law in Harris County, Texas.

"Grant Notice" means the separate notice given to each Recipient specifying the number of RSUs granted to the Recipient (the "Grant").

"Fair Market Value" means the fair market value of a share of the Stock as determined by the Committee by the reasonable application of such reasonable valuation method, consistently applied, as the Committee deems appropriate; provided, however, that if the Committee has not made such determination, such fair market value shall be the per share closing price of the Stock as reported on Nasdaq or on such other exchange or electronic trading system as, on the date in question, reports the largest number of traded shares of stock; provided further, however, that if there are no Stock transactions on such date, the Fair Market Value shall be determined as of the immediately preceding date on which there were Stock transactions.

"Involuntary Termination" means the termination of employment of the Recipient by the Company or its successor or an applicable Affiliate for any reason on or after a Change of Control; provided, that the termination does not result from an act of the Recipient that (i) constitutes common-law fraud, a felony, or a gross malfeasance of duty and (ii) is materially detrimental to the best interests of the Company or its successor; provided that, notwithstanding anything else in this Agreement to the contrary, an Involuntary Termination shall not be deemed to occur solely because a Recipient transfers employment from the Company to an Affiliate, from an Affiliate to the Company, or from one Affiliate to another Affiliate.

"Payout Amount" means the vested portion of the Grant expressed as an amount of cash equal to the Fair Market Value of the shares of Stock underlying the RSUs and related Dividend Equivalents.

"Recipient" means an Eligible Person designated by the Committee at the Grant Date to receive one or more Grants under the Plan.

"Retirement" means, with respect to a Recipient and for purposes of this Agreement, the date the Recipient terminates employment with the Company after attaining (i) age 55 and (ii) a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto.

"Years of Service" means the total number of months from the Recipient's date of hire by the Company to the date of termination of employment, plus any months required to be recognized under an appropriate acquisition agreement, divided by 12.

"Voluntary Termination with Cause" occurs upon a Recipient's separation from service of his or her own volition and one or more of the following conditions occurs without the Recipient's consent on or after a Change of Control:

(a) There is a material diminution in the Recipient's base compensation, compared to his or her rate of base compensation on the date of the Change of Control.

(b) There is a material diminution in the Recipient's authority, duties or responsibilities.

(c) There is a material diminution in the authority, duties or responsibilities of the Recipient's supervisor, such as a requirement that the Recipient (or his or her supervisor) report to a corporate officer or employee instead of reporting directly to the board of directors.

(d) There is a material diminution in the budget over which the Recipient retains authority.

(e) There is a material change in the geographic location at which the Recipient must perform his or her service, including, for example the assignment of the Recipient to a regular workplace that is more than 50 miles from his or her regular workplace on the date of the Change of Control.

The Recipient must notify the Company of the existence of one or more adverse conditions specified in clauses (a) through (e) above within 90 days of the initial existence of the adverse condition. The notice must be provided in writing to the

Company or its successor, attention: Vice President, Human Resources. The notice may be provided by personal delivery or it may be sent by email, inter-office mail, regular mail (whether or not certified), fax, or any similar method. The Company's Vice President, Human Resources, or his/her delegate shall acknowledge receipt of the notice within 5 business days; the acknowledgement shall be sent to the Recipient by certified mail. Notwithstanding the foregoing provisions of this definition, if the Company remedies the adverse condition within 30 days of being notified of the adverse condition, no Voluntary Termination with Cause shall occur.

Terms

1. Grant of RSUs. Subject to the provisions of this Agreement and the provisions of the Plan and Grant Notice, the Company shall grant to the Recipient, pursuant to the Plan, a right to receive the number of RSUs set forth in the Recipient's Grant Notice. The Grant shall give the Recipient the right, upon vesting, to receive an amount in cash equal to the Fair Market Value of an equal number of shares of $0.625 par value common stock of the Company ("Stock") to that of the number of RSUs set forth in the Recipient's Grant Notice. At the time of the Grant, the Recipient may elect to defer all or any portion of the RSUs in the Deferred Delivery Plan (the "DDP").

2. Vesting and Payment of Cash. Subject to the provisions of sections 3 and 4 of this Agreement, the entitlement to receive an amount of cash equal to the Fair Market Value of the number of shares of Stock pursuant to the RSUs comprising the Grant Amount shall vest in accordance with the schedule set forth in the Grant Notice (the "Vesting Period"); provided that the Recipient remains employed as an Eligible Person on such applicable vesting dates. Unless the Recipient elected to defer the RSU into the DDP, such cash, subject to applicable withholding, shall be paid by the Company to the Recipient within thirty (30) days of the vesting date (other than upon death or Disability). To the extent that the Recipient elected to defer the RSUs into the DDP and sections 3 and 4 do not apply, when the RSUs vest, an amount of cash equal to the Fair Market Value of the number of shares of Stock that have vested pursuant to the RSUs comprising the Grant Amount shall be paid to the DDP and paid thereafter to the Recipient as specified under the terms of the DDP.

3. Termination of Employment, Retirement, Death, or Disability. Except as set forth below in this section 3 and in section 4 of this Agreement, each Grant shall be subject to the condition that the Recipient has remained an Eligible Person from the award of the Grant of RSUs until the applicable vesting date as follows:

(a) If the Recipient voluntarily leaves the employment of the Company (other than for reason of Retirement), or if the employment of the Recipient is terminated by the Company for any reason or no reason, any RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall thereafter be void and forfeited for all purposes.

(b) If the Recipient leaves the employment of the Company by reason of Retirement, the RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall continue to vest following the Recipient's termination of employment by reason of Retirement as if the Recipient remained an Eligible Person in the employ of the Company, provided that such

Recipient shall be entitled to continue vesting only if such Recipient satisfies the Retirement Conditions set forth in section 5 below (except in the case of death) and only with respect to the specified percentage of such unvested RSUs set forth in Exhibit "A" for a certain combination of age and Years of Service attained by the Recipient as of the Recipient's Retirement under the Matrix set forth in Exhibit "A".

(c) A Recipient shall become 100% vested in all RSUs under the Grant Notice on the date the Recipient dies while employed by the Company regardless whether Recipient has accepted the Grant, or on the date the Recipient is no longer employed by the Company by reason of Disability, or, only in the case of death, while continuing to vest pursuant to section 3(b) of this Agreement. Payment shall be made as soon as administratively practicable, but in no event (i) in the case of death, shall the payment occur later than the last day of the calendar year following the calendar year in which such death occurs or (ii) in the case of cessation of employment by reason of Disability, shall the payment occur later than thirty (30) days following the date the Recipient is determined to be Disabled and is no longer employed by the Company. If clause (ii) is applicable and the period from the date on which the Recipient is determined to be Disabled and is no longer employed by the Company to the date under clause (ii) spans two consecutive calendar years, payment shall be made in the second calendar year of such consecutive calendar years. Such payment shall be made to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable. Each Recipient may designate a beneficiary on a form approved by the Committee.

4. Change of Control. Pursuant to Section 13.1(c)(iii) and (d) of the Plan, the following provisions of this section 4 of the Agreement shall supersede Sections 13.1(a), (b) and (c) of the Plan. Without any further action by the Committee or the Board, in the event of a Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of his or her Involuntary Termination or Voluntary Termination with Cause. Subject to section 11(b) of this Agreement, payment shall occur within thirty (30) days following the date of such Involuntary Termination or Voluntary Termination with Cause, subject to required tax withholding. Further, in the event of a Change of Control following the Recipient's termination of employment by reason of Retirement while the Recipient is continuing to vest in the RSUs pursuant to section 3(b) of this Agreement, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of the Change of Control (including those excluded by the specified percentage set forth in Exhibit "A"). Subject to section 11(b) of this Agreement, the Recipient, if the Recipient terminates employment on account of Retirement prior to the occurrence of a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs within thirty (30) days of the date of a 409A Change of Control, or if the Change of Control is not a 409A Change of Control, on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding. Further still, in the event of a Change of Control prior to the Recipient's termination of employment by reason of Retirement during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date the Recipient terminates employment by reason of Retirement (including those excluded by the specified percentage set forth in Exhibit "A"). For the purpose

of vesting as set forth in the prior sentence, a Recipient's Involuntary Termination or Voluntary Termination with Cause after a Change of Control shall be deemed a termination by reason of Retirement. Subject to section 11(b) of this Agreement, the Recipient, who terminates employment by reason of Retirement after a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding.

5. Conditions to Post-Retirement Vesting. If the Recipient has attained age 55 and a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto and terminates employment with the Company and the Affiliates by reason of Retirement, it is agreed by the Company and the Recipient that:

(a) subject to the provisions of this section 5(a) and sections 5(b) and 5(c), such Recipient shall continue to vest in the specified percentage of unvested RSUs set forth in Exhibit "A", for the combination of age and Years of Service attained by such Recipient as of his or her Retirement under the Matrix set forth in Exhibit "A", following the date of his or her termination by reason of Retirement as if the Recipient continued in employment as an Eligible Person provided that the Grant Date of the unvested RSUs is prior to such termination date in an amount of time which allows the Recipient to provide the written notice as follows and the Recipient has provided advance written notice not before three (3) months following the Grant Date and not less than the number of months prior to such termination date as set forth in the Schedule below to APA Corporation's Vice President, Human Resources, or his or her delegate, and to his or her direct manager, regarding the Recipient's intent to terminate employment for reason of Retirement; provided, however, a Recipient who is at least age 55 and attained the necessary combination of age and Years of Service under the Matrix set forth in Exhibit "A" for Retirement need not provide such advance written notice of his or her intent to terminate employment by reason of Retirement if the Company elects to require such Recipient to, or (as part of a reduction in force or otherwise in writing in exchange for a written release) offers such Recipient the opportunity to, terminate employment with the Company by reason of Retirement:

Age	Advance Written Notice
65 or older	3 months
between (and including) 55 and 64	6 months

; and it is further agreed that

(b) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the continuing Vesting Period after Retirement (the "Continued Vesting Period"), refrain from becoming employed by, or consulting with, or becoming substantially involved in the business of, any business that competes with the Company or its Affiliate in the business of exploration or production of oil or natural gas wherever from time to time conducted throughout the world (a "Competitive Business") and Recipient shall provide to the Company, upon Company's request, (x) a written certification, in a form provided by or satisfactory to the Company, as to Recipient's compliance with the forgoing conditions and/or (y) his/her U.S. Individual Income Tax Return for any return filed by the

Recipient which relates to any time during the Continued Vesting Period to allow the Company to verify that Recipient has complied with the foregoing conditions; provided, that the Recipient may purchase and hold for investment purposes less than five percent (5%) of the shares of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system, and provided further, that the Recipient may provide services solely as a director of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system if, during the Continued Vesting Period, (i) the Recipient only attends board and board committee meetings, votes on recommendations of management, and discharges his/her fiduciary obligations under the law and (ii) the Recipient is not involved in, and does not advise or consult on, the marketing, government relations, customer relations, or the day-to-day management, supervision, or operations of such Competitive Business; and it is further agreed that

(c) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the Continued Vesting Period, refrain from making, or causing or assisting any other person to make, any oral or written communication to any third party about the Company, any Affiliate and/or any of the employees, officers or directors of the Company or any Affiliate which impugns or attacks, or is otherwise critical of, the reputation, business or character of such entity or person; or that discloses private or confidential information about their business affairs; or that constitutes an intrusion into their seclusion or private lives; or that gives rise to unreasonable publicity about their private lives; or that places them in a false light before the public; or that constitutes a misappropriation of their name or likeness.

Notwithstanding the foregoing provisions of this section 5 of the Agreement, (i) in the event that the Recipient fails to satisfy any of the conditions set forth in sections 5(a), (b) and (c) above, the Recipient shall not be entitled to vest in any unvested RSUs after the date of Retirement and the unvested RSUs subject to this Agreement shall be forfeited and (ii) the Recipient shall not have any right to continue to vest upon Retirement in any future awards granted under the Plan once the Recipient provides the notice of Retirement as set forth in section 5(a) above.

6. Prohibited Activity. In consideration for this Grant and except as permitted under section 5(b) above, the Recipient agrees not to engage in any "Prohibited Activity" while employed by the Company or within three years after the date of the Recipient's termination of employment. A "Prohibited Activity" will be deemed to have occurred, as determined by the Committee in its sole and absolute discretion, if the Recipient (i) divulges any non-public, confidential or proprietary information of the Company, but excluding information that (a) becomes generally available to the public other than as a result of the Recipient's public use, disclosure, or fault, or (b) becomes available to the Recipient on a non-confidential basis after the Recipient's employment termination date from a source other than the Company prior to the public use or disclosure by the Recipient, provided that such source is not bound by a confidentiality agreement or otherwise prohibited from transmitting the information by contractual, legal or fiduciary obligation; (ii) directly or indirectly, consults with or becomes affiliated with, participate or engage in, or becomes employed by any business that is competitive with the Company, wherever from time to time conducted throughout the world, including situations where the Recipient solicits or participates in or assists in any way in the solicitation or recruitment, directly or indirectly, of any employees of the Company; or (iii)

engages in publishing any oral or written statements about the Company, and/or any of its directors, officers, or employees that are disparaging, slanderous, libelous, or defamatory; or that disclose private or confidential information about their business affairs; or that constitute an intrusion into their seclusion or private lives; or that give rise to unreasonable publicity about their private lives; or that place them in a false light before the public; or that constitute a misappropriation of their name or likeness.

7. Payment and Tax Withholding. Upon receipt of any entitlement to cash under this Agreement and, if applicable, upon the Recipient's attainment of eligibility to terminate employment by reason of Retirement pursuant to section 3(b), the Recipient shall make appropriate arrangements with the Company to provide for the amount of minimum tax and social security withholding, if any, required by law, including without limitation Sections 3102 and 3402 or any successor section(s) of the Internal Revenue Code and applicable state and local income and other tax laws. The payment of a Payout Amount shall be based on the Fair Market Value of the shares of Stock on the applicable date of vesting to which such tax withholding relates. Where appropriate, cash shall be withheld by the Company to satisfy applicable tax withholding requirements rather than paid directly to the Recipient.

8. Non-Transferability of Grant. A Grant shall not be transferable otherwise than by testamentary will or the laws of descent and distribution, or in accordance with a valid beneficiary designation on a form approved by the Committee, subject to the conditions and exceptions set forth in Section 15.2 of the Plan.

9. No Right to Continued Employment. Neither the RSUs or the cash payment pursuant to a Grant nor any terms contained in this Agreement shall confer upon the Recipient any express or implied right to be retained in the employment or service of the Company for any period, nor restrict in any way the right of the Company, which right is hereby expressly reserved, to terminate the Recipient's employment or service at any time for any reason or no reason. The Recipient acknowledges and agrees that any right to receive RSUs or cash pursuant to a Grant is earned only by continuing as an employee of the Company at the will of the Company, or satisfaction of any other applicable terms and conditions contained in the Plan and this Agreement, and not through the act of being hired, being granted the Grant, or acquiring RSUs or cash pursuant to the Grant hereunder.

10. The Plan. In consideration for this Grant, the Recipient agrees to comply with the terms of the Plan and this Agreement. This Agreement is subject to all the terms, provisions and conditions of the Plan, which are incorporated herein by reference, and to such regulations as may from time to time be adopted by the Committee. The Grant is a Cash-Based Award under Section 10 of the Plan and is subject to the provisions of the Plan governing RSUs. Unless defined herein, capitalized terms are used herein as defined in the Plan. In the event of any conflict between the provisions of the Plan and this Agreement, the provisions of the Plan shall control, and this Agreement shall be deemed to be modified accordingly. The Plan and the prospectus describing the Plan can be found on the Company's HR intranet and the Plan document can be found on Fidelity's website (netbenefits.fidelity.com). A paper copy of the Plan and the prospectus shall be provided to the recipient upon the Recipient's written request to the Company at 2000 Post Oak Blvd., Suite 100, Houston, Texas 77056-4400, Attention: Corporate Secretary.

11. Compliance with Laws and Regulations.

(a) The Grant and any obligation of the Company to deliver RSUs and cash hereunder shall be subject in all respects to (i) all applicable laws, rules and regulations and (ii) any registration, qualification, approvals or other requirements imposed by any government or regulatory agency or body which the Committee shall, in its discretion, determine to be necessary or applicable.

(b) This Grant is intended to comply with, or be exempt from, the applicable requirements of Section 409A of the Code and the rules and regulations issued thereunder and shall be administered accordingly. Notwithstanding anything in this Agreement to the contrary, if the RSUs constitute "deferred compensation" under Section 409A of the Code and any RSUs become payable pursuant to the Recipient's termination of employment, settlement of the RSUs shall be delayed for a period of six months after the Recipient's termination of employment if the Recipient is a "specified employee" as defined under Code Section 409A(a)(2)(B)(i) and if required pursuant to Section 409A of the Code. If settlement of the RSU is delayed, the RSUs shall be settled on the first day of the first calendar month following the end of the six-month delay period. If the Recipient dies during the six-month delay, the RSUs shall be settled and paid to the Recipient's designated beneficiary, legal representatives, heirs or legatees, as applicable, as soon as practicable after the date of death. Notwithstanding any provisions to the contrary herein, payments made with respect to this Grant may only be made in a manner and upon an event permitted by Section 409A of the Code, and all payments to be made upon a termination of employment hereunder may only be made upon a "separation from service", as such term is defined in Section 11.1 of the Plan. Recipient shall not have any right to determine a date of payment of any amount under this Agreement. This Agreement may be amended without the consent of the Recipient in any respect deemed by the Board or the Committee to be necessary in order to preserve compliance with Section 409A of the Code. If the Grant and this Agreement is subject to Section 409A of the Code and the rules and regulations issued thereunder, then the vesting date shall be the "designated payment date" or "specified date" under Treasury Regulation 1.409A-3(d).

12. Notices. Unless otherwise provided in this Agreement, all notices by the Recipient or the Recipient's assignees shall be addressed to the Administrative Agent, Fidelity, through the Recipient's account at netbenefits.fidelity.com, or such other address as the Company may from time to time specify. All notices to the Recipient shall be addressed to the Recipient at the Recipient's address in the Company's records.

13. Other Plans. The Recipient acknowledges that any income derived from the Grant shall not affect the Recipient's participation in, or benefits under, any other benefit plan or other contract or arrangement maintained by the Company or any Affiliate.

14. Terms of Employment. The Plan is a discretionary plan. The Recipient hereby acknowledges that neither the Plan nor this Agreement forms part of the Recipient's terms of employment and nothing in the Plan may be construed as imposing on the Company or any Affiliate a contractual obligation to offer participation in the Plan to any employee of the Company or any Affiliate. The Company or any Affiliate is under no obligation to make further Grants to any Recipient under the Plan. The Recipient hereby acknowledges that if the Recipient

ceases to be an employee of the Company or any Affiliate for any reason or no reason, the Recipient shall not be entitled by way of compensation for loss of office or otherwise howsoever to any sum.

15. Data Protection. By accepting this Agreement (whether by electronic means or otherwise), the Recipient hereby consents to the holding and processing of personal data provided by the Recipient to the Company for all purposes necessary for the operation of the Plan. These include, but are not limited to:

(a) administering and maintaining Recipient records;

(b) providing information to any registrars, brokers or third party administrators of the Plan; and

(c) providing information to future purchasers of the Company or the business in which the Recipient works.

16. Severability. If any provision of this Agreement is held invalid or unenforceable, the remainder of this Agreement shall nevertheless remain in full force and effect, and if any provision is held invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances, to the fullest extent permitted by law.

*****

Exhibit "A"

Apache Corporation
Retirement Matrix

Age at Retirement	Points (Age at Retirement + Years of Service)																				
	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%
69	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
68	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%
67	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
66	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
65	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
64	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
63	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
62	0%	0%	0%	0%	0%	0%	0%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
61	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
60	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
59	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
58	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
57	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
56	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
55	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%

0%
50%
75%
100%

Exhibit 10.43

SCHEDULE A

APA Corporation

Restricted Stock Unit Award Agreement

GRANT NOTICE

Recipient Name: [Name]

Company: APA Corporation

Notice: A summary of the terms of your grant of Restricted Stock Units ("RSUs") is set out in this notice (the "Grant Notice") but subject always to the terms of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan") and the Restricted Stock Unit Award Agreement (the "Agreement"). In the event of any inconsistency between the terms of this Grant Notice, the terms of the Plan and the Agreement, the terms of the Plan and the Agreement shall prevail.

You have been awarded a grant of APA Corporation RSUs in accordance with the terms of the Plan and the Agreement.

Details of the RSUs which you are entitled to receive is provided to you in this Grant Notice and maintained on your account at netbenefits.fidelity.com.

Type of Award: Restricted Stock Unit(s)

Restricted Stock Unit: A Restricted Stock Unit ("RSU") as defined in the Plan and meaning the right granted to the Recipient to receive one share of Stock for each RSU at the end of the specified Vesting Period.

Stock: The $0.625 par value common stock of the Company or as otherwise defined in the Plan.

Grant: A Grant related to ______ Restricted Stock Units.

Grant Date: [Date]

Conditions: The Recipient may elect, at the time of the grant, to have his or her RSUs deferred into the Deferred Delivery Plan (the "DDP") when the RSUs vest, in which case the Recipient will receive the value of the RSUs at the times specified pursuant to the DDP. For RSUs that are not deferred, once the RSU vests, the Recipient shall be

paid the value of his or her RSUs in shares of Stock (net of shares withheld for applicable tax withholdings) withheld for applicable tax withholdings).

Vesting Period: RSUs granted shall vest (i.e., restrictions shall lapse) in accordance with the following schedule (the "Vesting Period"), provided that the Recipient remains employed as an Eligible Person as of such vesting date:

First day of the month following the first anniversary of the Grant Date – 1/3 vested.

Second anniversary of the Grant Date – an additional 1/3 vested.

Third anniversary of the Grant Date – an additional 1/3 vested.

Notwithstanding the foregoing, if the Recipient's termination of employment from the Company and the Affiliates occurs by reason of his or her Retirement, the Recipient shall be deemed to continue to be employed as an Eligible Person for purposes of this Grant and shall continue to vest with respect to a specified percentage of RSUs over the Vesting Period set forth above provided that the Recipient meets the Retirement Conditions set forth in section 5 of the Agreement.

Upon vesting (other than upon death or Disability), the applicable shares of Stock, subject to required tax withholding, shall be transferred by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had elected to defer such RSUs into the DDP, in which case the RSUs shall be transferred to the DDP on the vesting date and paid out according to the provisions of the DDP.

Vesting is accelerated to 100% upon the Recipient's death or cessation of employment by reason of Disability while an Eligible Person (or, only in the case of death, while treated as an Eligible Person following Retirement as described above) during the Vesting Period. Upon vesting, the applicable shares of Stock, subject to required tax withholding, shall be transferred by the Company to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable, in accordance with the terms of the Plan and this Agreement. The Recipient can name a beneficiary on a form approved by the Committee.

Vesting is accelerated to 100% upon the Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control that occurs during the Vesting Period. With respect to a Recipient who continues to vest following his or her termination due to Retirement, vesting is accelerated to 100%

upon a Change of Control that occurs during the Vesting Period and on or after such termination by reason of Retirement. With respect to a Recipient who terminates employment by reason of Retirement after a Change of Control, vesting is accelerated to 100% upon the Recipient's termination of employment by reason of Retirement. Unless expressly otherwise provided in the Agreement with respect to Retirement and Change of Control, the applicable amount of shares of Stock, subject to required tax withholding, shall be transferred by the Company to the Recipient within thirty (30) days of the vesting date, unless the Recipient had

	elected to defer such RSUs into the DDP, in which case the RSUs shall be transferred to the DDP on the vesting date and paid out according to the provisions of the DDP.
Withholding:	The Company and the Recipient will comply with all federal and state laws and regulations respecting the required withholding, deposit, and payment of any income, employment, or other taxes relating to the Grant.
Dividends:	The Company will credit each of the Recipient's RSUs with Dividend Equivalents. For purposes of this Grant, a Dividend Equivalent is an amount equal to the cash dividend payable per share of Stock multiplied by the number of shares of Stock then underlying such outstanding RSUs. Such amount will be credited to a book entry account on Recipient's behalf at the time the Company pays any cash dividend on its Stock. The Recipient's rights in any such Dividend Equivalents will vest at the same time as, and only to the extent that, the underlying RSUs vest and will be distributed at the same time in cash (subject to applicable withholdings), and only to the extent, as the related RSUs are to be distributed to the Recipient as provided in the Agreement and to which such Dividend Equivalents apply.
Acceptance:	Please complete the on-line grant acceptance as promptly as possible to accept or reject your Grant. You can access this through your account at netbenefits.fidelity.com. By accepting your Grant, you will have agreed to the terms and conditions set forth in the Agreement, including, but not limited to, the non-compete and non-disparagement provisions set forth in sections 5 and 6 of the Agreement, and the terms and conditions of the Plan. If you do not accept your Grant, your RSUs will not vest and you will be unable to receive your RSUs.

APA Corporation

Restricted Stock Unit Award Agreement

This Restricted Stock Unit Award Agreement (the "Agreement") relating to a grant of Restricted Stock Units (as defined in the definition section of the APA Corporation 2016 Omnibus Compensation Plan (the "Plan")) (the "Grant"), dated as of the Grant Date set forth in the Notice of Award under the Agreement attached as Schedule A hereto (the "Grant Notice"), is made between APA Corporation (together with its Affiliates, the "Company") and each Recipient. The Grant Notice is included in and made part of this Agreement.

In this Agreement and each Grant Notice, unless the context otherwise requires, words and expressions shall have the meanings given to them in the Plan except as herein defined.

Definitions

"409A Change of Control" means a Change of Control that constitutes, with respect to APA Corporation, a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation" within the meaning of Section

409A(a)(2)(A)(v) of the Internal Revenue Code of 1986, as amended (the "Code") and Treasury Regulations Section 1.409A-3(i)(5).

"Disability" or "Disabled" means the Recipient is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. Recipient agrees that a final and binding determination of "Disability" will be made by the Company's representative under the Company's group long-term disability plan or any successor thereto or, if there is no such representative and there is a dispute as to the determination of "Disability," it will be decided in a court of law in Harris County, Texas.

"Grant Notice" means the separate notice given to each Recipient specifying the number of RSUs granted to the Recipient (the "Grant").

"Fair Market Value" means the fair market value of a share of the Stock as determined by the Committee by the reasonable application of such reasonable valuation method, consistently applied, as the Committee deems appropriate; provided, however, that if the Committee has not made such determination, such fair market value shall be the per share closing price of the Stock as reported on Nasdaq or on such other exchange or electronic trading system as, on the date in question, reports the largest number of traded shares of stock; provided further, however, that if there are no Stock transactions on such date, the Fair Market Value shall be determined as of the immediately preceding date on which there were Stock transactions.

"Involuntary Termination" means the termination of employment of the Recipient by the Company or its successor or an applicable Affiliate for any reason on or after a Change of Control; provided, that the termination does not result from an act of the Recipient that (i) constitutes common-law fraud, a felony, or a gross malfeasance of duty and (ii) is materially detrimental to the best interests of the Company or its successor; provided that, notwithstanding anything else in this Agreement to the contrary, an Involuntary Termination shall not be deemed to occur solely because a Recipient transfers employment from the Company to an Affiliate, from an Affiliate to the Company, or from one Affiliate to another Affiliate.

"Payout Amount" means the vested portion of the Grant, along with any Dividend Equivalents related thereto as specified in the Grant Notice, expressed as shares of Stock underlying the RSUs and related Dividend Equivalents.

"Recipient" means an Eligible Person designated by the Committee at the Grant Date to receive one or more Grants under the Plan.

"Retirement" means, with respect to a Recipient and for purposes of this Agreement, the date the Recipient terminates employment with the Company after attaining (i) age 55 and (ii) a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto.

"Years of Service" means the total number of months from the Recipient's date of hire by the Company to the date of termination of employment, plus any months required to be recognized under an appropriate acquisition agreement, divided by 12.

"Voluntary Termination with Cause" occurs upon a Recipient's separation from service of his or her own volition and one or more of the following conditions occurs without the Recipient's consent on or after a Change of Control:

(a) There is a material diminution in the Recipient's base compensation, compared to his or her rate of base compensation on the date of the Change of Control.

(b) There is a material diminution in the Recipient's authority, duties or responsibilities.

(c) There is a material diminution in the authority, duties or responsibilities of the Recipient's supervisor, such as a requirement that the Recipient (or his or her supervisor) report to a corporate officer or employee instead of reporting directly to the board of directors.

(d) There is a material diminution in the budget over which the Recipient retains authority.

(e) There is a material change in the geographic location at which the Recipient must perform his or her service, including, for example the assignment of the Recipient to a regular workplace that is more than 50 miles from his or her regular workplace on the date of the Change of Control.

The Recipient must notify the Company of the existence of one or more adverse conditions specified in clauses (a) through (e) above within 90 days of the initial existence of the adverse condition. The notice must be provided in writing to the

Company or its successor, attention: Vice President, Human Resources. The notice may be provided by personal delivery or it may be sent by email, inter-office mail, regular mail (whether or not certified), fax, or any similar method. The Company's Vice President, Human Resources, or his/her delegate shall acknowledge receipt of the notice within 5 business days; the acknowledgement shall be sent to the Recipient by certified mail. Notwithstanding the foregoing provisions of this definition, if the Company remedies the adverse condition within 30 days of being notified of the adverse condition, no Voluntary Termination with Cause shall occur.

Terms

1. Grant of RSUs. Subject to the provisions of this Agreement and the provisions of the Plan and Grant Notice, the Company shall grant to the Recipient, pursuant to the Plan, a right to receive the number of RSUs set forth in the Recipient's Grant Notice. The Grant shall give the Recipient the right, upon vesting, to an equal number of shares of $0.625 par value common stock of the Company ("Stock"). At the time of the Grant, the Recipient may elect to defer all or any portion of the RSUs in the Deferred Delivery Plan (the "DDP").

2. Vesting and Payment of Stock. Subject to the provisions of sections 3 and 4 of this Agreement, the entitlement to receive the number of shares of Stock pursuant to the RSUs comprising the Grant Amount shall vest in accordance with the schedule set forth in the Grant Notice (the "Vesting Period"); provided that the Recipient remains employed as an Eligible Person on such applicable vesting dates. Unless the Recipient elected to defer the RSU into the DDP, such Stock, subject to applicable withholding, shall be transferred by the Company to the Recipient within thirty (30) days of the vesting date (other than upon death or Disability). To the extent that the Recipient elected to defer the RSUs into the DDP and sections 3 and 4 do not apply, when the RSUs vest, they shall be transferred to the DDP and paid thereafter to the Recipient as specified under the terms of the DDP.

3. Termination of Employment, Retirement, Death, or Disability. Except as set forth below in this section 3 and in section 4 of this Agreement, each Grant shall be subject to the condition that the Recipient has remained an Eligible Person from the award of the Grant of RSUs until the applicable vesting date as follows:

(a) If the Recipient voluntarily leaves the employment of the Company (other than for reason of Retirement), or if the employment of the Recipient is terminated by the Company for any reason or no reason, any RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall thereafter be void and forfeited for all purposes.

(b) If the Recipient leaves the employment of the Company by reason of Retirement, the RSUs granted to the Recipient pursuant to the Grant Notice not previously vested shall continue to vest following the Recipient's termination of employment by reason of Retirement as if the Recipient remained an Eligible Person in the employ of the Company, provided that such Recipient shall be entitled to continue vesting only if such Recipient satisfies the Retirement Conditions set forth in section 5 below (except in the case of death) and only with respect to the specified percentage of such unvested RSUs set forth in Exhibit "A" for a certain combination of

age and Years of Service attained by the Recipient as of the Recipient's Retirement under the Matrix set forth in Exhibit "A".

(c) A Recipient shall become 100% vested in all RSUs under the Grant Notice on the date the Recipient dies while employed by the Company regardless whether Recipient has accepted the Grant, or on the date the Recipient is no longer employed by the Company by reason of Disability, or, only in the case of death, while continuing to vest pursuant to section 3(b) of this Agreement. Payment shall be made as soon as administratively practicable, but in no event (i) in the case of death, shall the payment occur later than the last day of the calendar year following the calendar year in which such death occurs or (ii) in the case of cessation of employment by reason of Disability, shall the payment occur later than thirty (30) days following the date the Recipient is determined to be Disabled and is no longer employed by the Company. If clause (ii) is applicable and the period from the date on which the Recipient is determined to be Disabled and is no longer employed by the Company to the date under clause (ii) spans two consecutive calendar years, payment shall be made in the second calendar year of such consecutive calendar years. Such payment shall be made to the Recipient's designated beneficiary, legal representatives, heirs, or legatees, as applicable. Each Recipient may designate a beneficiary on a form approved by the Committee.

4. Change of Control. Pursuant to Section 13.1(c)(iii) and (d) of the Plan, the following provisions of this section 4 of the Agreement shall supersede Sections 13.1(a), (b) and (c) of the Plan. Without any further action by the Committee or the Board, in the event of a Recipient's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of his or her Involuntary Termination or Voluntary Termination with Cause. Subject to section 12(d) of this Agreement, payment shall occur within thirty (30) days following the date of such Involuntary Termination or Voluntary Termination with Cause, subject to required tax withholding. Further, in the event of a Change of Control following the Recipient's termination of employment by reason of Retirement while the Recipient is continuing to vest in the RSUs pursuant to section 3(b) of this Agreement, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date of the Change of Control (including those excluded by the specified percentage set forth in Exhibit "A"). Subject to section 12(d) of this Agreement, the Recipient, if the Recipient terminates employment on account of Retirement prior to the occurrence of a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs within thirty (30) days of the date of a 409A Change of Control, or if the Change of Control is not a 409A Change of Control, on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding. Further still, in the event of a Change of Control prior to the Recipient's termination of employment by reason of Retirement during the Vesting Period, the Recipient shall become 100% fully vested in the unvested RSUs granted to the Recipient pursuant to the Grant Notice as of the date the Recipient terminates employment by reason of Retirement (including those excluded by the specified percentage set forth in Exhibit "A"). For the purpose of vesting as set forth in the prior sentence, a Recipient's Involuntary Termination or Voluntary Termination with Cause after a Change of Control shall be deemed a termination by reason of Retirement. Subject to section 12(d) of this Agreement, the Recipient, who terminates

employment by reason of Retirement after a Change of Control, shall receive payment with respect to 100% of the fully vested RSUs on the remaining vesting dates during the Vesting Period in the amount of 1/3 (on each of the remaining vesting dates) of the RSUs awarded as of the Grant Date, subject to required tax withholding.

5. Conditions to Post-Retirement Vesting. If the Recipient has attained age 55 and a certain combination of age and Years of Service set forth in the Matrix in Exhibit "A" attached hereto and terminates employment with the Company and the Affiliates by reason of Retirement, it is agreed by the Company and the Recipient that:

(a) subject to the provisions of this section 5(a) and sections 5(b) and 5(c), such Recipient shall continue to vest in the specified percentage of unvested RSUs set forth in Exhibit "A", for the combination of age and Years of Service attained by such Recipient as of his or her Retirement under the Matrix set forth in Exhibit "A", following the date of his or her termination by reason of Retirement as if the Recipient continued in employment as an Eligible Person provided that the Grant Date of the unvested RSUs is prior to such termination date in an amount of time which allows the Recipient to provide the written notice as follows and the Recipient has provided advance written notice not before three (3) months following the Grant Date and not less than the number of months prior to such termination date as set forth in the Schedule below to APA Corporation's Vice President, Human Resources, or his or her delegate, and to his or her direct manager, regarding the Recipient's intent to terminate employment for reason of Retirement; provided, however, a Recipient who is at least age 55 and attained the necessary combination of age and Years of Service under the Matrix set forth in Exhibit "A" for Retirement need not provide such advance written notice of his or her intent to terminate employment by reason of Retirement if the Company elects to require such Recipient to, or (as part of a reduction in force or otherwise in writing in exchange for a written release) offers such Recipient the opportunity to, terminate employment with the Company by reason of Retirement:

Age	Advance Written Notice
65 or older	3 months
between (and including) 55 and 64	6 months

; and it is further agreed that

(b) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the continuing Vesting Period after Retirement (the "Continued Vesting Period"), refrain from becoming employed by, or consulting with, or becoming substantially involved in the business of, any business that competes with the Company or its Affiliate in the business of exploration or production of oil or natural gas wherever from time to time conducted throughout the world (a "Competitive Business") and Recipient shall provide to the Company, upon Company's request, (x) a written certification, in a form provided by or satisfactory to the Company, as to Recipient's compliance with the forgoing conditions and/or (y) his/her U.S. Individual Income Tax Return for any return filed by the Recipient which relates to any time during the Continued Vesting Period to allow the Company to verify that Recipient has complied with the foregoing conditions; provided, that the Recipient may purchase and hold for investment purposes less than five percent (5%) of the shares of any

Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system, and provided further, that the Recipient may provide services solely as a director of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system if, during the Continued Vesting Period, (i) the Recipient only attends board and board committee meetings, votes on recommendations of management, and discharges his/her fiduciary obligations under the law and (ii) the Recipient is not involved in, and does not advise or consult on, the marketing, government relations, customer relations, or the day-to-day management, supervision, or operations of such Competitive Business; and it is further agreed that

(c) in consideration for the continued vesting treatment afforded to the Recipient under section 5(a), Recipient shall, during the Continued Vesting Period, refrain from making, or causing or assisting any other person to make, any oral or written communication to any third party about the Company, any Affiliate and/or any of the employees, officers or directors of the Company or any Affiliate which impugns or attacks, or is otherwise critical of, the reputation, business or character of such entity or person; or that discloses private or confidential information about their business affairs; or that constitutes an intrusion into their seclusion or private lives; or that gives rise to unreasonable publicity about their private lives; or that places them in a false light before the public; or that constitutes a misappropriation of their name or likeness.

Notwithstanding the foregoing provisions of this section 5 of the Agreement, (i) in the event that the Recipient fails to satisfy any of the conditions set forth in sections 5(a), (b) and (c) above, the Recipient shall not be entitled to vest in any unvested RSUs after the date of Retirement and the unvested RSUs subject to this Agreement shall be forfeited and (ii) the Recipient shall not have any right to continue to vest upon Retirement in any future awards granted under the Plan once the Recipient provides the notice of Retirement as set forth in section 5(a) above.

6. Prohibited Activity. In consideration for this Grant and except as permitted under section 5(b) above, the Recipient agrees not to engage in any "Prohibited Activity" while employed by the Company or within three years after the date of the Recipient's termination of employment. A "Prohibited Activity" will be deemed to have occurred, as determined by the Committee in its sole and absolute discretion, if the Recipient (i) divulges any non-public, confidential or proprietary information of the Company, but excluding information that (a) becomes generally available to the public other than as a result of the Recipient's public use, disclosure, or fault, or (b) becomes available to the Recipient on a non-confidential basis after the Recipient's employment termination date from a source other than the Company prior to the public use or disclosure by the Recipient, provided that such source is not bound by a confidentiality agreement or otherwise prohibited from transmitting the information by contractual, legal or fiduciary obligation; (ii) directly or indirectly, consults with or becomes affiliated with, participate or engage in, or becomes employed by any business that is competitive with the Company, wherever from time to time conducted throughout the world, including situations where the Recipient solicits or participates in or assists in any way in the solicitation or recruitment, directly or indirectly, of any employees of the Company; or (iii) engages in publishing any oral or written statements about the Company, and/or any of its directors, officers, or employees that are disparaging, slanderous, libelous, or defamatory; or that disclose private or confidential information about their business affairs; or that constitute an

intrusion into their seclusion or private lives; or that give rise to unreasonable publicity about their private lives; or that place them in a false light before the public; or that constitute a misappropriation of their name or likeness.

7. Payment and Tax Withholding. Upon receipt of any entitlement to Stock under this Agreement and, if applicable, upon the Recipient's attainment of eligibility to terminate employment by reason of Retirement pursuant to section 3(b), the Recipient shall make appropriate arrangements with the Company to provide for the amount of minimum tax and social security withholding, if any, required by law, including without limitation Sections 3102 and 3402 or any successor section(s) of the Internal Revenue Code and applicable state and local income and other tax laws. Upon receipt of entitlement to Stock under this Agreement, each payment of the Payout Amount shall be made in shares of Stock, determined by the Committee, such that the withheld number of shares of Stock shall be sufficient to cover the withholding amount required by this section (including any amount to cover benefit tax charges arising thereon). The payment of a Payout Amount shall be based on the Fair Market Value of the shares of Stock on the applicable date of vesting to which such tax withholding relates. Where appropriate, shares of Stock shall be withheld by the Company to satisfy applicable tax withholding requirements rather than paid directly to the Recipient.

8. No Ownership Rights Prior to Issuance of Stock. Neither the Recipient nor any other person shall become the beneficial owner of the Stock underlying the Grant, nor have any rights of a shareholder (including, without limitation, dividend and voting rights) with respect to any such Stock, unless and until and after such Stock has been actually issued to the Recipient and transferred on the books and records of the Company or its agent in accordance with the terms of the Plan and this Agreement.

9. Non-Transferability of Grant. A Grant shall not be transferable otherwise than by testamentary will or the laws of descent and distribution, or in accordance with a valid beneficiary designation on a form approved by the Committee, subject to the conditions and exceptions set forth in Section 15.2 of the Plan.

10. No Right to Continued Employment. Neither the RSUs or Stock issued pursuant to a Grant nor any terms contained in this Agreement shall confer upon the Recipient any express or implied right to be retained in the employment or service of the Company for any period, nor restrict in any way the right of the Company, which right is hereby expressly reserved, to terminate the Recipient's employment or service at any time for any reason or no reason. The Recipient acknowledges and agrees that any right to receive RSUs or Stock pursuant to a Grant is earned only by continuing as an employee of the Company at the will of the Company, or satisfaction of any other applicable terms and conditions contained in the Plan and this Agreement, and not through the act of being hired, being granted the Grant, or acquiring RSUs or Stock pursuant to the Grant hereunder.

11. The Plan. In consideration for this Grant, the Recipient agrees to comply with the terms of the Plan and this Agreement. This Agreement is subject to all the terms, provisions and conditions of the Plan, which are incorporated herein by reference, and to such regulations as may from time to time be adopted by the Committee. Unless defined herein, capitalized terms are used herein as defined in the Plan. In the event of any conflict between the provisions of the

Plan and this Agreement, the provisions of the Plan shall control, and this Agreement shall be deemed to be modified accordingly. The Plan and the prospectus describing the Plan can be found on the Company's HR intranet and the Plan document can be found on Fidelity's website (netbenefits.fidelity.com). A paper copy of the Plan and the prospectus shall be provided to the recipient upon the Recipient's written request to the Company at 2000 Post Oak Blvd., Suite 100, Houston, Texas 77056-4400, Attention: Corporate Secretary.

12. Compliance with Laws and Regulations.

(a) The Grant and any obligation of the Company to deliver RSUs or Stock hereunder

(a) The Grant and any obligation of the Company to deliver RSUs or Stock hereunder shall be subject in all respects to (i) all applicable laws, rules and regulations and (ii) any registration, qualification, approvals or other requirements imposed by any government or regulatory agency or body which the Committee shall, in its discretion, determine to be necessary or applicable. Moreover, the Company shall not deliver any certificates for Stock to the Recipient or any other person pursuant to this Agreement if doing so would be contrary to applicable law. If at any time the Company determines, in its discretion, that the listing, registration or qualification of Stock upon any national securities exchange or under any applicable law, or the consent or approval of any governmental regulatory body, is necessary or desirable, the Company shall not be required to deliver any certificates for Stock to the Recipient or any other person pursuant to this Agreement unless and until such listing, registration, qualification, consent or approval has been effected or obtained, or otherwise provided for, free of any conditions not acceptable to the Company.

(b) It is intended that the issuance of any Stock received in respect of the Grant shall have been registered under the Securities Act of 1933 ("Securities Act"). If the Recipient is an "affiliate" of the Company, as that term is defined in Rule 144 under the Securities Act ("Rule 144"), the Recipient may not sell the Stock received except in compliance with Rule 144. Certificates representing Stock issued to an "affiliate" of the Company may bear a legend setting forth such restrictions on the disposition or transfer of the Stock as the Company deems appropriate to comply with Federal and state securities laws.

(c) If, at any time, a registration statement with respect to the issuance of the Stock is not effective under the Securities Act, and/or there is no current prospectus in effect under the Securities Act with respect to the Stock, the Recipient shall execute, prior to the delivery of any Stock to the Recipient by the Company pursuant to this Agreement, an agreement (in such form as the Company may specify) in which the Recipient represents and warrants that the Recipient is purchasing or acquiring the Stock acquired under this Agreement for the Recipient's own account, for investment only and not with a view to the resale or distribution thereof, and represents and agrees that any subsequent offer for sale or distribution of any kind of such Stock shall be made only pursuant to either (i) a registration statement on an appropriate form under the Securities Act, which registration statement has become effective and is current with regard to the Stock being offered or sold, or (ii) a specific exemption from the registration requirements of the Securities Act, but in claiming such exemption the Recipient shall, prior to any offer for sale of such Stock, obtain a prior favorable written opinion, in form and substance satisfactory to the Company, from counsel for or approved by the Company, as to the applicability of such exemption thereto.

(d) This Grant is intended to comply with, or be exempt from, the applicable requirements of Section 409A of the Code and the rules and regulations issued thereunder and shall be administered accordingly. Notwithstanding anything in this Agreement to the contrary, if the RSUs constitute "deferred compensation" under Section 409A of the Code and any RSUs become payable pursuant to the Recipient's termination of employment, settlement of the RSUs shall be delayed for a period of six months after the Recipient's termination of employment if the Recipient is a "specified employee" as defined under Code Section 409A(a)(2)(B)(i) and if required pursuant to Section 409A of the Code. If settlement of the RSU is delayed, the RSUs shall be settled on the first day of the first calendar month following the end of the six-month delay period. If the Recipient dies during the six-month delay, the RSUs shall be settled and paid to the Recipient's designated beneficiary, legal representatives, heirs or legatees, as applicable, as soon as practicable after the date of death. Notwithstanding any provisions to the contrary herein, payments made with respect to this Grant may only be made in a manner and upon an event permitted by Section 409A of the Code, and all payments to be made upon a termination of employment hereunder may only be made upon a "separation from service", as such term is defined in Section 11.1 of the Plan. Recipient shall not have any right to determine a date of payment of any amount under this Agreement. This Agreement may be amended without the consent of the Recipient in any respect deemed by the Board or the Committee to be without the consent of the Recipient in any respect deemed by the Board or the Committee to be necessary in order to preserve compliance with Section 409A of the Code. If the Grant and this Agreement is subject to Section 409A of the Code and the rules and regulations issued thereunder, then the vesting date shall be the "designated payment date" or "specified date" under Treasury Regulation 1.409A-3(d).

13. Notices. Unless otherwise provided in this Agreement, all notices by the Recipient or the Recipient's assignees shall be addressed to the Administrative Agent, Fidelity, through the Recipient's account at netbenefits.fidelity.com, or such other address as the Company may from time to time specify. All notices to the Recipient shall be addressed to the Recipient at the Recipient's address in the Company's records.

14. Other Plans. The Recipient acknowledges that any income derived from the Grant shall not affect the Recipient's participation in, or benefits under, any other benefit plan or other contract or arrangement maintained by the Company or any Affiliate.

15. Terms of Employment. The Plan is a discretionary plan. The Recipient hereby acknowledges that neither the Plan nor this Agreement forms part of the Recipient's terms of employment and nothing in the Plan may be construed as imposing on the Company or any Affiliate a contractual obligation to offer participation in the Plan to any employee of the Company or any Affiliate. The Company or any Affiliate is under no obligation to grant further RSUs or Stock to any Recipient under the Plan. The Recipient hereby acknowledges that if the Recipient ceases to be an employee of the Company or any Affiliate for any reason or no reason, the Recipient shall not be entitled by way of compensation for loss of office or otherwise howsoever to any sum.

16. Data Protection. By accepting this Agreement (whether by electronic means or otherwise), the Recipient hereby consents to the holding and processing of personal data provided by the Recipient to the Company for all purposes necessary for the operation of the Plan. These include, but are not limited to:

(a) administering and maintaining Recipient records;

(b) providing information to any registrars, brokers or third party administrators of the Plan; and

(c) providing information to future purchasers of the Company or the business in which the Recipient works.

17. Severability. If any provision of this Agreement is held invalid or unenforceable, the remainder of this Agreement shall nevertheless remain in full force and effect, and if any provision is held invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances, to the fullest extent permitted by law.

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Apache Corporation
Retirement Matrix

		Points (Age at Retirement + Years of Service)																				
		60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
Age at Retirement	70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%
	69	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
	68	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%
	67	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	66	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	65	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	64	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
	63	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
	62	0%	0%	0%	0%	0%	0%	0%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
	61	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
	60	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
	59	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
	58	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
	57	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
	56	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
	55	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%

0%
50%
75%
100%

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2021

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
APA Dominican Republic Corporation LDC	Cayman Islands
APA Egypt Investment Corporation LDC	Cayman Islands
APA EIF Holdings, Inc.	Delaware
APA Exploration LDC	Cayman Islands
APA International Exploration LDC	Cayman Islands
APA Netherlands Investment B.V.	The Netherlands
APA Netherlands Investment II B.V.	The Netherlands
APA Suriname Corporation LDC	Cayman Islands
APA Suriname 58 Holdings Corporation LDC	Cayman Islands
APA Suriname 58 Corporation LDC	Cayman Islands
Apache Corporation	Delaware
Alta Vista Oil Corporation	Delaware
*Altus Midstream Company	Delaware
*Altus Midstream GP LLC	Delaware
**Altus Midstream Subsidiary GP LLC	Delaware
Apache Alaska Corporation	Delaware
Apache Corporation (New Jersey)	New Jersey
Apache Crude Oil Marketing, Inc.	Delaware
Apache Deepwater LLC	Texas
Apache Fertilizer Holdings II Corporation LDC	Cayman Islands
Apache Finance Louisiana Corporation	Delaware
Apache Foundation	Minnesota
Apache Finance Pty Limited	Australian Capital Territory
Apache Gathering Company	Delaware
Apache Holdings, Inc.	Delaware
Apache International Employment Inc.	Delaware
Apache Louisiana Holdings LLC	Delaware
Apache Louisiana Minerals LLC	Delaware
Apache Marketing, Inc.	Delaware
Apache Midstream LLC	Delaware
Alpine High Oil Pipeline LLC	Delaware
Apache Natural Gas Transportation Fuels LLC	Delaware
Apache North America LLC	Delaware
Apache Oil Corporation	Texas
Apache Overseas LLC	Delaware
Apache Asia Pacific Corporation LDC	Cayman Islands
Apache East Ras Budran Corporation LDC	Cayman Islands
Apache Egypt GP Corporation LDC	Cayman Islands
Apache Egypt Holdings III Corporation LDC	Cayman Islands
Apache Egypt Holdings II Corporation LDC	Cayman Islands
Apache Abu Gharadig Corporation LDC	Cayman Islands
Apache East Bahariya Corporation LDC	Cayman Islands
Apache El Diyur Corporation LDC	Cayman Islands
Apache Faiyum Corporation LDC	Cayman Islands
Apache Khalda Corporation LDC	Cayman Islands
Apache Egypt Midstream Holdings I LDC	Cayman Islands
Apache Khalda II Corporation LDC	Cayman Islands
Apache Matruh Corporation LDC	Cayman Islands
Apache Mediterranean Corporation LDC	Cayman Islands
Apache North Bahariya Corporation LDC	Cayman Islands
Apache North El Diyur Corporation LDC	Cayman Islands

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2021

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
Apache North Tarek Corporation LDC	Cayman Islands
Apache Qarun Corporation LDC	Cayman Islands
Apache Qarun Exploration Company LDC	Cayman Islands
Apache Shushan Corporation LDC	Cayman Islands
Apache South Umbarka Corporation LDC	Cayman Islands
Apache Umbarka Corporation LDC	Cayman Islands
Apache West Kalabsha Corporation LDC	Cayman Islands
Apache West Kanayis Corporation LDC	Cayman Islands
Apache UK Consolidated Holdings Corporation LDC	Cayman Islands
Apache UK Corporation LDC	Cayman Islands
Apache International Corporation LDC	Cayman Islands
Apache North Sea Limited	England and Wales
Apache UK Pension Trustee Ltd.	England and Wales
Apache North Sea Production Limited	England and Wales
Apache UK Investment Limited	England and Wales
Apache Beryl I Limited	Cayman Islands
Apache EMEA Corporation LDC	Cayman Islands
Apache Exploration LDC	Cayman Islands
Apache Fertilizer Holdings Corporation LDC	Cayman Islands
Apache International Finance S.a.r.l.	Luxembourg
Apache International Finance II S.a.r.l.	Luxembourg
Apache Latin America II Corporation LDC	Cayman Islands
Apache Overseas Holdings LLC	Delaware
Apache Switzerland Holdings AG	Switzerland
Apache Overseas Holdings II, Inc.	Delaware
Apache Ravensworth Corporation LDC	Cayman Islands
Apache Shady Lane Ranch Inc.	Delaware
Apache Shelf Exploration LLC	Texas
Apache Shelf, Inc.	Delaware
Apache Texas Property Holding Company LLC	Delaware
Apache Well Containment LLC	Delaware
Apache Western Exploration LLC	Delaware
BLPL Holdings LLC	Delaware
Clear Creek Hunting Preserve, Inc.	Wyoming
Cordillera Energy Partners III, LLC	Colorado
Cottonwood Aviation, Inc.	Delaware
CV Energy Corporation	Delaware
DEK Energy LLC	Delaware
Apache Finance Canada LLC	Delaware
Apache Permian Basin Investment LLC	Delaware
Apache Permian Basin Corporation	Delaware
Apache Permian Exploration and Production LLC	Delaware
LeaCo New Mexico Exploration and Production LLC	Delaware
Permian Basin Joint Venture LLC (95%)	Delaware
ZPZ Delaware I LLC	Delaware
Apache Canada Management LLC	Delaware
Apache Canada Holdings LLC	Delaware
Apache Canada Management II LLC	Delaware
Apache Finance Canada III LLC	Delaware
Apache Finance Canada IV LLC	Delaware
Stallion Canada Holdings LLC	Delaware

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2021

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
Edge Petroleum Exploration Company	Delaware
Granite Operating Company	Texas
Phoenix Exploration Resources, Ltd.	Delaware
Texas International Company	Delaware
Texas and New Mexico Exploration LLC	Delaware
ZPZ Acquisitions, Inc.	Delaware
ZPZ Delaware II LLC	Delaware
ZPZ Delaware III LLC	Delaware
Phoenix Exploration Louisiana C LLC (75%)	Delaware

***Apache Corporation owns a 79.19% voting interest and a 9.76% economic interest.**
****Apache Corporation owns a 79.19% voting and economic interest.**

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-257556) of APA Corporation, and
(2) Registration Statement (Form S-8 No. 333-253754) of APA Corporation

of our reports dated February 22, 2022, with respect to the consolidated financial statements of APA Corporation and subsidiaries and the effectiveness of internal control over financial reporting of APA Corporation and subsidiaries, included in this Annual Report (Form 10-K) of APA Corporation for the year ended December 31, 2021.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2022

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

Consent of Ryder Scott Company, L.P.

As independent petroleum engineers, we hereby consent to the incorporation by reference in this Form 10-K of APA Corporation to our Firm's name and our Firm's review of the proved oil and gas reserve quantities of APA Corporation as of December 31, 2021, to the incorporation by reference of our Firm's name and review into APA Corporation's previously filed Registration Statements on Form S-3 (No. 333-257556) and on Form S-8 (No. 333-253754), and to the inclusion of our report, dated January 21, 2022, as an exhibit to this Form 10-K filed with the Securities and Exchange Commission.

/s/ Ryder Scott Company, L.P.

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

Houston, Texas
February 22, 2022

SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

EXHIBIT 31.1

CERTIFICATIONS

I, John J. Christmann IV, certify that:

1. I have reviewed this Annual Report on Form 10-K of APA Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 22, 2022

/s/ John J. Christmann IV

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

EXHIBIT 31.2

CERTIFICATIONS

I, Stephen J. Riney, certify that:

1. I have reviewed this Annual Report on Form 10-K of APA Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 22, 2022

/s/ Stephen J. Riney

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

EXHIBIT 32.1

APA CORPORATION

Certification of Principal Executive Officer
and Principal Financial Officer

I, John J. Christmann IV, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of APA Corporation for the period ending December 31, 2021, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of APA Corporation.

Date: February 22, 2022

/s/ John J. Christmann IV

By:	John J. Christmann IV
Title:	Chief Executive Officer and President (principal executive officer)

I, Stephen J. Riney, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of APA Corporation for the period ending December 31, 2021, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of APA Corporation.

Date: February 22, 2022

/s/ Stephen J. Riney

By:	Stephen J. Riney
Title:	Executive Vice President and Chief Financial Officer (principal financial officer)

APACHE CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

and

Derived Through Certain Production Sharing Contracts

SEC Parameters

As of

December 31, 2021

/s/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Senior Vice President

[SEAL]

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 FAX (713) 651-0849 TELEPHONE (713) 651-9191

January 21, 2022

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

Ladies and Gentlemen:

At the request of Apache Corporation (Apache), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2021 prepared by Apache's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on January 17, 2022 and presented herein, was prepared for public disclosure by Apache in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Apache's estimated net reserves attributable to the leasehold and royalty interests and derived through certain production sharing contracts in certain properties owned by Apache and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2021. The properties reviewed by Ryder Scott incorporate Apache's reserves determinations and are attributable to the interests of Apache Corporation (U.S.A), Apache Egypt Companies (Egypt), and Apache North Sea Limited (United Kingdom).

The properties reviewed by Ryder Scott account for a portion of Apache's total net proved reserves as of December 31, 2021. Based on the estimates of total net proved reserves prepared by Apache, the reserves audit conducted by Ryder Scott addresses 82.4 percent of the total proved developed net liquid hydrocarbon reserves, 78.9 percent of the total proved developed net gas reserves, 70.9 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 72.9 percent of the total proved undeveloped net gas reserves of Apache.

The wells or locations for which estimates of reserves were reviewed by Ryder Scott were selected by Apache. Apache informed Ryder Scott that the selected reserves for each country included at least 81.5 percent or more of the total proved discounted future net income at 10 percent attributable to the respective country's total interests of Apache (coverage) based on SEC hydrocarbon price parameters as of December 31, 2021. Total coverage of world-wide reserves is 83.3 percent of the total proved discounted future net income at 10 percent.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or

Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2021 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Apache has informed us that in the preparation of their reserves and income projections, as of December 31, 2021, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Apache attributable to Apache's interest and entitlement in properties that we reviewed and the reserves of properties that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
Apache Corporation (Total All Countries)
As of December 31, 2021

				Reviewed by Ryder Scott			Not Reviewed			Total		
	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF
Developed	84.0	79.0	78.9	306,303	131,642	1,402,696	58,383	35,038	375,725	364,686	166,680	1,778,421
Undeveloped	67.6	77.9	72.9	23,602	12,999	146,924	11,326	3,686	54,551	34,928	16,685	201,475
Total Proved	82.6	78.9	78.3	329,905	144,641	1,549,620	69,709	38,724	430,276	399,614	183,365	1,979,896

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
Apache Corporation (Summary by Country)
As of December 31, 2021

	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Reviewed by Ryder Scott			Not Reviewed			Total		
				Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMcf	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMcf	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMcf
USA												
Developed	85.3	79.0	77.8	154,308	129,754	963,089	26,660	34,419	274,372	180,968	164,173	1,237,461
Undeveloped	75.4	77.6	74.7	13,697	12,719	137,858	4,471	3,661	46,583	18,168	16,380	184,441
Total Proved	84.4	78.9	77.4	168,005	142,473	1,100,947	31,131	38,080	320,955	199,136	180,553	1,421,902
Egypt												
Developed	82.3	87.9	82.2	87,758	393	381,841	18,887	54	82,965	106,645	447	464,806
Undeveloped	57.1	16.7	19.6	6,282	5	1,942	4,721	25	7,968	11,003	30	9,910
Total Proved	79.9	83.4	80.8	94,040	398	383,783	23,608	79	90,933	117,648	477	474,716
United Kingdom												
Developed	83.3	72.6	75.9	64,237	1,495	57,766	12,836	565	18,388	77,073	2,060	76,154
Undeveloped	62.9	100.0	100.0	3,623	275	7,124	2,134	0	0	5,757	275	7,124
Total Proved	81.9	75.8	77.9	67,860	1,770	64,890	14,970	565	18,388	82,830	2,335	83,278

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousand of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed reserves included herein consist of the producing, shut-in and behind pipe status categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Apache's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

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

Audit Data, Methodology, Procedure and Assumptions

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

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

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

The proved reserves, prepared by Apache, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2021, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Apache or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method or analogy. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Apache for our review or which we have obtained from public data sources that were available through November 2021. The data utilized from the analogues in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Apache relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Apache for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2021 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices, provided by Apache, appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Apache for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements. In cases where there are numerous contracts or price references within the same geographic area, the benchmark price is represented by the unweighted arithmetic average of the initial 12-month average first-day-of-the-month benchmark prices used.

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

The table below summarizes Apache's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Apache's "average realized prices." The average realized prices shown in the table below were determined from Apache's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Apache's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the following table is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$66.56/Bbl	$65.67/Bbl
	NGLs	Mt. Belvieu Non-Tet Propane	$44.06/Bbl	$28.83/Bbl
	Gas	Henry Hub	$3.61/MMBTU	$3.20/Mcf
Egypt	Oil/Condensate	Brent	$69.23/Bbl	$68.01/Bbl
	NGLs	Brent	$69.23/Bbl	$49.91/Bbl
	Gas	Contracts	Contract	$2.82/Mcf
United Kingdom	Oil/Condensate	Brent	$69.23/Bbl	$68.78/Bbl
	NGLs	Brent	$69.23/Bbl	$40.95/Bbl
	Gas	UK National Balancing Point (NBP)	$14.02/MMBTU	$12.53/Mcf

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

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Apache are based on the operating expense reports of Apache and include only those costs directly applicable to the leases, contract areas, or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas, and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases, contract areas, and wells under terms of operating agreements. Other costs include transportation and/or processing fees as deductions. The operating costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Apache are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. The estimated net cost of abandonment after salvage was included by Apache for properties where abandonment costs net of salvage were material. Apache's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Apache's plans to develop these reserves as of December 31, 2021. The implementation of Apache's development plans as presented to us is subject to the approval process adopted by Apache's management. As the result of our inquiries during the course of our review, Apache has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Apache's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Apache. Apache has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Apache has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

Apache's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Apache to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Apache. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Apache's estimates due to unforeseen factors causing a change in the timing to initiate production.

Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

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

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain.

The proved reserves for the properties located in Egypt are subject to the contractual fiscal terms contained in production sharing contracts. For these properties, Ryder Scott audited the gross economic inputs used by Apache in the economic models for Egypt through a comparison of Apache and Ryder Scott's gross economic volumes. Apache's gross economic volumes were then used as input to the economic models to generate the net interests used to determine the net reserves summarized in this report. Ryder Scott reviewed the fiscal terms of such contracts and discussed with Apache the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Apache's representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Apache operates or has interests. Apache's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the quantities as estimated by Apache.

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

Certain technical personnel of Apache are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Apache has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Apache's forecast of future proved production, we have relied upon data furnished by Apache with respect to property interests owned or derived, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Apache. We consider the factual data furnished to us by Apache to be appropriate and sufficient for the purpose of our review of Apache's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Apache and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2021 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Apache in their estimate of proved reserves to be effective and in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Apache's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Apache's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Apache when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned or derived by Apache.

Other Properties

Other properties, as used herein, are those properties of Apache which we did not review. The proved net reserves attributable to the other properties account for 17.6 percent of the total proved developed net liquid hydrocarbon reserves, 21.1 percent of the total proved developed net gas reserves, 29.1 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 27.1 percent of the total proved undeveloped net gas reserves based on estimates prepared by Apache as of December 31, 2021. The other properties represent 16.7 percent of the total proved discounted future net income at 10 percent based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by Apache as of December 31, 2021.

The same technical personnel of Apache were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

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

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

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

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Apache Corporation.

Apache makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Apache has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3, Form S-4, and Form S-8 of Apache, of the references to our name, as well as to the references to our third party report for Apache, which appears in the December 31, 2021 annual report on Form 10-K of Apache. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Apache.

We have provided Apache with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Apache and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

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

/s/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Senior Vice President [SEAL]

AAP (FWZ)/pl

Professional Qualifications of Primary Technical Person

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

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

Mr. Porbandarwala earned a Bachelor of Science degree in Chemical Engineering from The University of Kansas in 2001 and a Masters in Business Administration from The University of Texas at Austin in 2007 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers. Mr. Porbandarwala also served as the Chairman of the annual Ryder Scott Reserves Conference in Houston, completing its seventeenth year in the industry.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Porbandarwala fulfills. As part of his 2021 continuing education hours, Mr. Porbandarwala attended 20 hours of formalized training including the 2021 Virtual Ryder Scott Reserves Conference and various other professional society presentations specifically relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register.

Based on his educational background, professional training and more than 13 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Porbandarwala has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

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

PREAMBLE

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

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

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

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

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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

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

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

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

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

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

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

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

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

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

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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

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

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

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