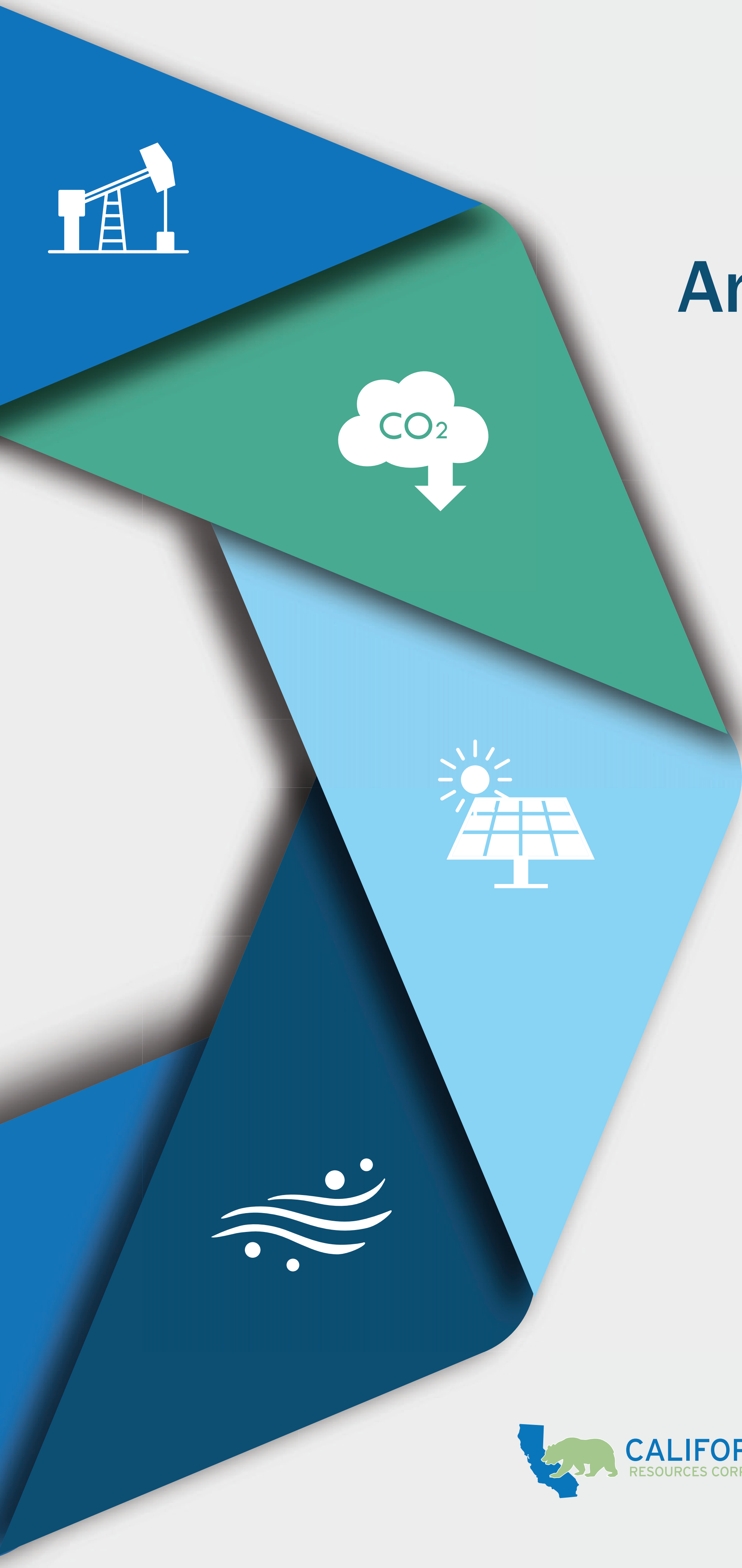


2024 Annual Report

CALIFORNIA RESOURCES CORPORATION | CARBON TERRAVAULT

FINANCIAL & OPERATIONAL HIGHLIGHTS

FINANCIAL HIGHLIGHTS		2024		2023		2022
Dollar amounts in millions, except share and per-share amounts, as of and for the years ended December 31						
Total Operating Revenues	$	3,198	$	2,801	$	2,707
Net Income	$	376	$	564	$	524
Adjusted Net Income[(a)]	$	317	$	372	$	384
Net Income per Share – Diluted	$	4.62	$	7.78	$	6.75
Adjusted Net Income per Share – Diluted[(a)]	$	3.89	$	5.13	$	4.95
Net Cash Provided by Operating Activities	$	610	$	653	$	690
Capital Investments	$	255	$	185	$	379
Free Cash Flow[(a)]	$	355	$	468	$	311
Net Cash Provided by (Used in) Financing Activities	$	343	$	(289)	$	(371)
Total Assets	$	7,135	$	3,998	$	3,967
Long-Term Debt, Net	$	1,132	$	540	$	592
Stockholders' Equity	$	3,538	$	2,219	$	1,864
Weighted-Average Shares Outstanding - Diluted		81.4		72.5		77.6
Year-End Shares		91.1		68.7		71.9

OPERATIONAL HIGHLIGHTS		2024		2023		2022
Average Daily Net Production:						
Oil (MBbl/d)		80		52		55
NGLs (MBbl/d)		10		11		11
Natural Gas (MMcf/d)		117		135		147
Total (MBoe/d)[(b)]		110		86		91
Average Realized Prices:						
Oil with hedge ($/Bbl)	$	75.66	$	65.97	$	61.80
Oil without hedge ($/Bbl)	$	76.92	$	80.41	$	98.26
NGLs ($/Bbl)	$	48.93	$	48.94	$	64.33
Natural Gas ($/Mcf)	$	2.99	$	8.59	$	7.68
Proved Reserves:						
Oil (MMBbl)		443		256		294
NGLs (MMBbl)		34		35		38
Natural Gas (Bcf)		409		518		511
Total (MMBoe)[(b)]		545		377		417
Standardized Measure of Discounted Future Net Cash Flows (in billions)	$	6.7	$	4.1	$	6.7
PV-10 of Cash Flows (in billions)[(a)]	$	8.9	$	5.5	$	9.2
Net Mineral Acreage (in thousands):						
Developed		757		684		689
Undeveloped		1,106		1,008		1,178
Total		1,863		1,692		1,867
Closing Share Price	$	51.89	$	54.68	$	43.51

(a) See www.crc.com, Investor Relations for a discussion of these performance and non-GAAP measures, including a reconcililation to the most closely related GAAP measure or information on the related calculations.
(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

2024 CEO Annual Report Letter

Dear Shareholders,

2024 was a transformative year for California Resources Corporation (CRC), marked by growth, operational excellence and innovation. We made remarkable progress across our business and continue to demonstrate that CRC is truly ***a Different Kind of Energy Company***. By successfully executing our business plan, we delivered meaningful value to shareholders and positioned CRC for long-term success.

Our success in 2024 can be attributed to three key factors:

1. *Our combination with Aera Energy was transformative, creating scale and a more sustainable enterprise.* We demonstrated our ability to execute on a strategic merger and capture synergies that drive future returns. As the industry continues to consolidate into stronger and more financially sound companies, CRC is well positioned to lead.
2. *CRC's conventional oil and gas business performed exceptionally well*. Our low decline, quality reservoirs generated a significant amount of cash flow, which we strategically allocated to strengthen our balance sheet, reward shareholders and expand into new growth opportunities.
3. *Our Carbon TerraVault (CTV) business achieved key milestones reinforcing our path to future revenues and profitability.* We cleared critical regulatory gateways, announced our first carbon capture project and strengthened CTV's position as a premier carbon management solutions provider. Today, leading companies recognize our unique value proposition and are partnering with us on large scale projects to decarbonize California.

A key driver of our 2024 financial performance was the successful integration of Aera, which significantly expanded our scale, strengthened cash flow, and drove operational efficiencies. With Aera, CRC's gross production increased by over 70% and exited the year at 163 Mboe/d, with 79% oil. This accretive growth helped CRC generate $610 million of net cash flow provided by operating activities, $355 million in free cash flow[1] and adjusted EBITDAX[1] exceeded $1 billion—reflecting the strength and resilience of our expanded portfolio.

The operational and financial impact of the merger was immediate, nearly doubling our proved reserves while enhancing cash flow resilience through a more diversified asset portfolio. Beyond scale, we rapidly executed on synergies—originally targeting $150 million, we increased this to $235 million, with over 70% already actioned. These efficiencies lowered our breakevens, enabling us to maintain capital discipline while significantly growing shareholder returns.

We remained committed to returning capital to shareholders, increasing our dividend by 25% and distributing approximatively 85% of free cash flow[1] through dividends and share buybacks.

Our strong balance sheet also benefited from the Aera merger—we quickly rebuilt cash reserves, exiting 2024 with $1.3 billion in liquidity[1] and over $350 million in cash on hand. With a larger, stronger, and more resilient business, we enter 2025 well-positioned to drive further efficiencies, sustain strong free cash flow generation, and execute on new growth opportunities.

Looking Ahead to 2025

Our 2025 business plan includes capital investments in the range of $285 million to $335 million, targeting average net production of 135 Mboe/d, with 79% oil. We continue to capture Aera-related synergies and drive operational efficiencies; our controllable costs are expected to decline by approximatively 11% year-over-year in 2025.

CTV is entering a new stage as we expect to break ground on critical projects, including our Elk Hills cryogenic gas plant and an agreement with National Cement for a first-of-its-kind initiative to produce carbon-neutral cement at National Cement's facility in California. We also have seven Class VI permits pending Environmental Protection Agency approval, with nearly 9 million metric tons per annum of carbon projects under consideration[2] across key economic sectors such as power, construction, agriculture, renewable fuels and others.

Other aspects of our business, like power, are gaining momentum. Today, we have access to nearly 850 MW of capacity[3], and our Resource Adequacy payments are set to increase by 50% in 2025 to $150 million. As California's largest natural gas producer, we see additional upside driven by growing demand.

As our business flourishes, we expect that our shareholders will continue to be rewarded. We recognize the importance of sustainable capital returns and since mid-2021, we have returned more than $1.1 billion to stakeholders through repurchases, dividends and debt reduction.

We believe CRC is uniquely positioned with high quality assets, a proven track record of execution, a strong capital structure and emerging growth opportunities. Our achievements would not be possible without the dedication and expertise of our talented workforce. Their commitment to safety, innovation, and operational excellence continues to drive our success. Thank you to our employees for their hard work, and to our investors for your continued trust in CRC.

We are excited for the future and tackling California's complex energy challenges while advancing the state's emissions reduction goals. One thing is clear: demand for low-carbon, reliable energy is growing in California and *CRC will be here to provide it.*

Francisco Leon
President and Chief Executive Officer
California Resources Corporation

[1] Represents a non-GAAP measure. For all historical non-GAAP financial measures please see the Investor Relations page at www.crc.com for a reconciliation to the nearest GAAP equivalent and other additional information. Free cash flow is equal to net cash provided (used) by operating activities less capital investments.

[2] Please see CRC's 4Q24 earnings presentation for a complete list of CRC's CCS projects under consideration.

[3] Please see Part I, Items 1 & 2 – Business and Properties, Infrastructure of CRC's Form 10-K for additional information.

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2024

☐ **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 001-36478

California Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1 World Trade Center, Suite 1500
Long Beach, California 90831
(Address of principal executive offices) (Zip Code)

(888) 848-4754
(Registrant's telephone number, including area code)

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	CRC	New York Stock Exchange

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 Date File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or such shorter period as 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. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. Common Stock aggregate market value held by non-affiliates as of June 30, 2024: $3,592,717,138.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

At January 31, 2025, there were 90,778,229 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement to be filed within 120 days after December 31, 2024 with the Securities and Exchange Commission in connection with the registrant's 2024 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

GLOSSARY AND SELECTED ABBREVIATIONS

The following are abbreviations and definitions of certain terms used within this Form 10-K:

- ***AB*** - Assembly Bill
- ***ABR*** - Alternate base rate.
- ***Aera*** - Aera Energy LLC.
- ***Aera Merger*** - The transactions contemplated by the Merger Agreement.
- ***ASC*** - Accounting Standards Codification.
- ***ARO*** - Asset retirement obligation.
- ***Bbl*** - Barrel.
- ***Bbl/d*** - Barrels per day.
- ***Bcf*** - Billion cubic feet.
- ***Bcfe*** - Billion cubic feet of natural gas equivalent using the ratio of one barrel of oil, condensate, or NGLs converted to six thousand cubic feet of natural gas.
- ***Boe*** - We convert natural gas volumes to crude oil equivalents using a ratio of six thousand cubic feet (Mcf) to one barrel of crude oil equivalent based on energy content. This is a widely used conversion method in the oil and natural gas industry.
- ***Boe/d*** - Barrel of oil equivalent per day.
- ***Brookfield*** - BGTF Sierra Aggregator LLC.
- ***Btu*** - British thermal unit.
- ***CalGEM*** - California Geologic Energy Management Division.
- ***CAISO*** - California Independent System Operator.
- ***Carbon TerraVault JV*** - A joint venture between our wholly-owned subsidiary Carbon TerraVault I, LLC with Brookfield for the further development of a carbon management business in California.
- ***CCS*** - Carbon capture and storage.
- ***CDMA*** - Carbon Dioxide Management Agreement.
- ***CEQA*** - California Environmental Quality Act.
- ***CO_2*** - Carbon dioxide.
- ***DAC*** - Direct air capture.
- ***DD&A*** - Depletion, depreciation, and amortization.
- ***EOR*** - Enhanced oil recovery.
- ***EPA*** - United States Environmental Protection Agency.
- ***ESG*** - Environmental, social and governance.
- ***E&P*** - Exploration and production.
- ***Full-Scope Net Zero*** - Achieving permanent storage of captured or removed carbon emissions in a volume equal to all of our scope 1, 2 and 3 emissions by 2045.
- ***GAAP*** - United States Generally Accepted Accounting Principles.
- **G&A** - General and administrative expenses.
- ***GHG*** - Greenhouse gases.
- ***JV*** - Joint venture.
- ***LCFS*** - Low Carbon Fuel Standard.
- ***MBbl*** - One thousand barrels of crude oil, condensate or NGLs.
- ***MBbl/d*** - One thousand barrels per day.
- ***MBoe/d*** - One thousand barrels of oil equivalent per day.
- ***MBw/d*** - One thousand barrels of water per day
- ***Mcf*** - One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six thousand cubic feet of natural gas.
- ***Merger Agreement*** - Definitive agreement and plan of merger related to the transactions to obtain all of the ownership interests in Aera.
- ***MHp*** - One thousand horsepower.
- ***MMBbl*** - One million barrels of crude oil, condensate or NGLs.

- ***MMBoe*** - One million barrels of oil equivalent.
- ***MMBtu*** - One million British thermal units.
- ***MMcf/d*** - One million cubic feet of natural gas per day.
- ***MMT*** - Million metric tons.
- ***MMTPA*** - Million metric tons per annum.
- ***MW*** - Megawatts of power.
- ***NGLs*** - Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as purity products such as ethane, propane, isobutane and normal butane, and natural gasoline.
- ***NYMEX*** - The New York Mercantile Exchange.
- ***OCTG*** - Oil country tubular goods.
- ***Oil spill prevention rate*** - Calculated as total Boe less net barrels lost divided by total Boe.
- ***OPEC*** - Organization of the Petroleum Exporting Countries.
- ***OPEC+*** - OPEC together with Russia and certain other producing countries.
- ***PHMSA*** - Pipeline and Hazardous Materials Safety Administration.
- ***Proved developed reserves*** - Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- ***Proved reserves*** - The estimated quantities of natural gas, NGLs, and oil that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic conditions, operating methods and government regulations.
- ***Proved undeveloped reserves*** - Proved reserves that are expected to be recovered from new wells on undrilled acreage that are reasonably certain of production when drilled or from existing wells where a relatively major expenditure is required for recompletion.
- ***PSCs*** - Production-sharing contracts.
- ***PV-10*** - Non-GAAP financial measure and represents the year-end present value of estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.
- ***SB*** - Senate Bill
- ***Scope 1 emissions*** - Our direct emissions.
- ***Scope 2 emissions*** - Indirect emissions from energy that we use (*e.g.*, electricity, heat, steam, cooling) that is produced by others.
- ***Scope 3 emissions*** - Indirect emissions from upstream and downstream processing and use of our products.
- ***SDWA*** - Safe Drinking Water Act.
- ***SEC*** - United States Securities and Exchange Commission.
- ***SEC Prices*** - The unweighted arithmetic average of the first day-of-the-month price for each month within the year used to determine estimated volumes and cash flows for our proved reserves.
- ***SOFR*** - Secured overnight financing rate as administered by the Federal Reserve Bank of New York.
- ***Standardized measure*** - The year-end present value of after-tax estimated future cash flows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum and using SEC Prices. Standardized measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions.
- ***TRIR*** - Total Recordable Incident Rate calculated as recordable incidents per 200,000 hours for all workers (employees and contractors).
- ***Working interest*** - The right granted to a lessee of a property to explore for and to produce and own oil, natural gas or other minerals in-place. A working interest owner bears the cost of development and operations of the property.
- ***WTI*** - West Texas Intermediate.

PART I

ITEMS 1 & 2 BUSINESS AND PROPERTIES

Business

We are an independent energy and carbon management company committed to energy transition. We are committed to environmental stewardship while safely providing local, responsibly sourced energy. We are also focused on maximizing the value of our land, mineral ownership, and energy expertise for decarbonization by developing carbon capture and storage (CCS) and other emissions-reducing projects.

Our principal business consists of two segments: oil and natural gas and carbon management. The oil and natural gas segment explores for, develops and produces crude oil, oil condensate, natural gas liquids and natural gas. The carbon management segment, which we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and underground storage facilities. Our carbon management segment also owns an investment in the Carbon TerraVault JV. For more information on our segments, refer to *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Segment Results of Oil and Natural Gas Operations* and *Results of our Carbon Management Segment,* and *Part II, Item 8 – Financial Statements and Supplementary Data, Note 16 Segment Information*.

On July 1, 2024, we obtained by way of merger all of the ownership interests in Aera. The Aera Merger added significant oil-weighted production and proved developed reserves to CRC, primarily in the San Joaquin and Ventura basins. In connection with the closing of the Aera Merger, we issued 21,315,707 shares of common stock to the former Aera owners (Sellers) and expect to issue additional shares during 2025 in connection with post-closing settlement. As of July 1, 2024, and immediately following the closing of the Aera Merger, our existing stockholders prior to the Aera Merger owned 76% of CRC and the Sellers owned 24% of CRC. We also paid approximately $990 million in connection with the extinguishment of all of Aera's outstanding indebtedness. For more information on the Aera Merger, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger*.

Except when the context otherwise requires or where otherwise indicated, all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its consolidated subsidiaries as of the date presented.

Business Strategy

- **Focus on integration and synergy capture of the Aera assets to enable future consolidation opportunities.** We are focused on reducing costs and improving operating efficiencies as a result of the Aera Merger. In 2024, we implemented synergies that we expect will result in future annual cost savings of $170 million, and we expect to implement additional synergies in 2025 that will result in a further $65 million in such cost savings. As the largest producer in California, we believe that we will have the opportunity to acquire additional producing assets in California at attractive valuations and we expect to pursue other acquisitions within or outside of California.
- **Maintain high standards of operational performance to drive profitability and create reliable cash flows**. For the year ended December 31, 2024, we generated $376 million in net income including the results of Aera's operations for the second half of the year. We intend to maintain high standards for safe and environmentally responsible operations, while also seeking to drive further efficiencies in our business through innovation and lowering costs and enhance cash flows in different commodity price environments and industry cycles.

- **Maintain a disciplined and flexible capital program**. We expect to allocate capital among assets based on permit availability and manage field-level development. Over the short term, we intend to primarily invest in workovers and sidetracks to take advantage of permit availability. When permitting for new wells resumes, we plan to invest in developing wells with high returns and short payback metrics. We expect to fund our capital program primarily from operating cash flows and maintain a flexible approach to adapt to fluctuations in commodity prices and changes in the regulatory climate.
- **Preserve balance sheet strength and shareholder returns**. As of December 31, 2024, we had $1,337 million of liquidity, consisting of $983 million available for borrowing under the Revolving Credit Facility (after taking into account $167 million of outstanding letters of credit) and $354 million in cash on hand. We had $1,145 million of long term indebtedness as of the same date. By maintaining significant liquidity and low leverage, we believe we will be able to ensure a strong financial foundation that will allow us to focus on shareholder returns, including dividends and share repurchases.
- **Advance our carbon management business to lead the energy transition**. We are focused on maximizing the value of our land, mineral and technical resources for decarbonization by developing CCS and other emissions reducing projects. We expect to deliver industrial-scale projects to help California meet its decarbonization goals. We intend to leverage our Carbon TerraVault JV with Brookfield to reduce our capital investments to develop these projects. We are also focused on maximizing opportunities and optimizing long term value for our existing natural gas fired power generation assets, including our 550 MW power plant at Elk Hills.
- **Proactively and collaboratively engage in matters related to regulation and HSE matters**. We seek to work with regulators and legislators at the state and local levels in an effort to minimize potential adverse impacts that new legislation and regulations may have on our business and operations. Our commitment to health, safety and the environment (HSE) defines how we operate our business. We intend to always produce energy in a safe and responsible manner to help support and enhance the quality of life in the communities in which we operate.
- **Maintain our commitment to environmental stewardship**. We intend to continue efforts to reduce CO_2 and methane emissions in our operations. We also intend to continue to proactively manage our idle wells and reduce our consumption of freshwater in our operations. We are committed to transparency in these efforts and intend to continue to disclose our progress regularly, including through our annual sustainability report. We expect to continue to seek third party certifications of our results and disclosure practices, such as MIQ's certification of methane emissions.

Oil and Natural Gas Segment

The following table highlights key information about our oil and natural gas segment as of and for the year ended December 31, 2024:

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total Operations
Mineral Acreage					
Net mineral acreage (thousands)	1,277	35	421	130	1,863
Average net mineral acreage held in fee (%)	89 %	55 %	47 %	88 %	79 %
Number of producing fields we operate[(a)]	38	4	21	2	65
Average drilling rigs	1	—	—	—	1
Net wells drilled and completed	8.0	—	—	—	8.0
Proved reserves					
Oil (MMBbl)	344	77	—	22	443
NGLs (MMBbl)	33	—	—	1	34
Natural gas (Bcf)	383	5	18	3	409
Total (MMBoe)	441	78	3	23	545
Oil percentage of proved reserves	78 %	99 %	— %	96 %	81 %
Production					
Total net production (MMBoe)	31	6	1	2	40
Average daily net production (MBoe/d)[(b)]	85	17	2	6	110

(a) We reduced the number of producing fields reported in 2023 by removing certain fields that were classified as abandoned, shut-in or non-producing. This change has no impact on our production volumes.

(b) 2 MBoe/d of production in the Salinas Basin for the year ended December 31, 2024 is included in Other Basins. Salinas Basin production was included in the San Joaquin Basin in prior periods.

For a discussion of the regulatory issues affecting the development of our oil and natural gas properties, see *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities.*

San Joaquin Basin

Commercial petroleum development in the San Joaquin basin began in the 1800s. The basin contains multiple stacked formations throughout its areal extent, and we believe that this basin provides appealing opportunities for re-development of existing wells, as well as new discoveries and unconventional play potential. The geology of the San Joaquin basin continues to yield stratigraphic and structural trap discoveries.

We have interests in oil and gas fields throughout the San Joaquin basin, including in Elk Hills, Buena Vista, Coles Levee, North Belridge and South Belridge, Kern Front, Lost Hills, Cymric, McKittrick, Midway Sunset and Coalinga.

We hold substantially all of the working and mineral interests in the Belridge field. We operate the Belridge field, which consists of the North Belridge and South Belridge fields. The Belridge field consists of waterflood and steamflood operations. In the steamfloods we utilize natural gas that is both purchased from third parties and produced from our other fields. Our operations at Belridge include a central control facility with remote automation control on over 95% of the producing wells.

We hold substantially all the working, surface and mineral interests in the Elk Hills field. We operate efficient natural gas processing facilities, including a cryogenic gas plant, with a combined gas processing capacity of 330 MMcf/d. Additionally, our Elk Hills power plant generates electricity to power our oil and gas operations at Elk Hills and other nearby producing fields. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of the producing wells.

We believe our extensive 3D seismic library, which covers over 800,000 acres in the San Joaquin basin, or over 50% of our gross mineral acreage in this basin, gives us a competitive advantage in field development.

Los Angeles Basin

This basin is a northwest-trending plain about 50 miles long and 20 miles wide. Most of the significant discoveries in the Los Angeles basin date back to the 1920s. The Los Angeles basin has one of the highest concentrations per acre of crude oil in the world. We have significant operations in the Wilmington field, which is a large active oil field in this basin. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) under which we first recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and then receive our share of profits. See *Production, Price and Cost History* below for more information on our PSCs.

Sacramento Basin

The Sacramento basin is a deep, thick sequence of sedimentary deposits of natural gas within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918.

Other Basins

We have oil and natural gas operations in other basins in California, including the Ventura and Salinas basins. We also have mineral interests in undeveloped acreage throughout California, including the Santa Maria basin which is located in San Luis Obispo County and Santa Barbara County.

Mineral Acreage

The following table summarizes our gross and net developed and undeveloped mineral acreage as of December 31, 2024.

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total
			(in thousands)		
Developed[(a)]					
Gross[(b)]	543	22	243	14	822
Net[(c)]	495	16	233	13	757
Undeveloped[(d)]					
Gross[(b)]	918	21	222	143	1,304
Net[(c)]	782	19	188	117	1,106
Total					
Gross[(b)]	1,461	43	465	157	2,126
Net[(c)]	1,277	35	421	130	1,863

(a) Mineral acres spaced or assigned to productive wells.
(b) Total number of mineral acres in which interests are owned.
(c) Net mineral acreage includes acreage reduced to our fractional ownership interest and interests under our PSCs.
(d) Mineral acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the mineral acreage contains proved reserves.

At December 31, 2024, 79% of our total net mineral interest position was held in fee and the remainder was leased. Of our leased acreage, approximately 85% is held by production and the remainder is subject to lease expiration if initial wells are not drilled within a specified period of time. The primary terms of our leases range from one to twenty years. The terms of these leases are typically extended upon achieving commercial production for so long as such production is maintained. Work programs are designed to ensure that the economic potential of any leased property is evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for leasing that acreage. In cases where we determine we want to take the additional time required to fully evaluate undeveloped acreage, we have generally been successful in obtaining extensions.

If we are not able to establish production or otherwise extend lease terms, approximately 9,000 net mineral acres will expire in 2025, 6,000 net mineral acres will expire in 2026 and 7,000 net mineral acres will expire in 2027. These leases represent 2% of our total net undeveloped acreage and 1% of our total net acreage as of December 31, 2024 and these expirations, should they occur, would not have a material adverse effect on us. Historically, we have not dedicated any significant portion of our capital program to prevent lease expirations and do not expect to do so in the future.

Production, Price and Cost History

The following table sets forth information regarding our production volumes, average realized and benchmark prices and operating costs per Boe (presented before and after hedges) for the periods presented. See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations* for more information on our production activity as well as the impact of price increases of certain commodities used in our operations and on our operating costs per Boe, among other factors.

	Year Ended December 31,		
	2024	2023	2022
Average daily net production			
Oil (MBbl/d)	80	52	55
NGLs (MBbl/d)	10	11	11
Natural gas (MMcf/d)	117	135	147
Total daily net production (MBoe/d)	110	86	91
Total production (MMBoe)	40	31	33
Average realized prices			
Oil with hedge ($/Bbl)	$ 75.66	$ 65.97	$ 61.80
Oil without hedge ($/Bbl)	$ 76.92	$ 80.41	$ 98.26
NGLs ($/Bbl)	$ 48.93	$ 48.94	$ 64.33
Natural gas without hedge ($/Mcf)	$ 2.99	$ 8.59	$ 7.68
Average benchmark prices			
Brent oil ($/Bbl)	$ 79.84	$ 82.22	$ 98.89
WTI oil ($/Bbl)	$ 75.72	$ 77.62	$ 94.23
NYMEX gas ($/MMBtu) - Average Monthly Settled Price	$ 2.27	$ 2.74	$ 6.64
Operating costs per Boe			
Operating costs	$ 24.51	$ 26.24	$ 23.75
Operating costs, after hedges	$ 25.31	$ 26.24	$ 23.75

Oil, natural gas and NGL production for our two largest fields for the year ended December 31, 2024 are presented in the table below:

	Belridge	Elk Hills
	2024	2024
Average daily net production		
Oil (MBbl/d)	34	14
NGLs (MBbl/d)	—	7
Natural gas (MMcf/d)	—	59
Total daily net production (MBoe/d)	34	31

Oil, natural gas and NGL production for our two largest fields for the years ended December 31, 2023 and 2022 are presented in the table below:

	Elk Hills		Wilmington	
	2023	2022	2023	2022
Average daily net production				
Oil (MBbl/d)	16	17	16	15
NGLs (MBbl/d)	8	8	—	—
Natural gas (MMcf/d)	68	75	—	—
Total daily net production (MBoe/d)	35	38	16	15

Our operating costs include (1) variable costs that fluctuate with production levels and (2) fixed costs that typically do not vary with changes in production levels or well counts, especially in the short term. The substantial majority of our near-term fixed costs become variable over the longer term because we manage them based on the field's stage of life and operating characteristics. For example, portions of labor and material costs, energy, workovers and maintenance expenditures correlate to well count, production and activity levels. Portions of these same costs can be relatively fixed over the near term; however, they are managed down as fields mature in a manner that correlates to production and commodity price levels. A certain amount of costs for facilities, surface support, surveillance and related maintenance can be regarded as fixed in the early phases of a program. However, as the production from a certain area matures, well count increases and daily per well production drops, such support costs can be reduced and consolidated over a larger number of wells, reducing costs per operating well. Further, many of our other costs, such as property taxes and oilfield services, are variable and will respond to activity levels and tend to correlate with commodity prices. We can quickly scale our operating costs in response to prevailing market conditions. We believe that a significant portion of our operating costs is variable over the lifecycle of our fields.

Our share of production and reserves from operations in the Wilmington field in the Los Angeles basin is subject to contractual arrangements similar to PSCs that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production, and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented 12% of our total production for the year ended December 31, 2024.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in operating costs on our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

The following table presents our operating costs after adjustment for excess costs attributable to PSCs for the periods presented:

	Year ended December 31,					
	2024		2023		2022	
	(in millions)	($ per Boe)	(in millions)	($ per Boe)	(in millions)	($ per Boe)
Operating costs[a]	$ 983	$ 24.51	$ 822	$ 26.24	$ 785	$ 23.75
Excess costs attributable to PSCs	(67)	(1.67)	(71)	(2.25)	(74)	$ (2.23)
Operating costs, excluding effects of PSCs[b]	$ 916	$ 22.84	$ 751	$ 23.99	$ 711	$ 21.52

(a) Operating costs related to our exploration and production activities and are presented before elimination entries beginning in 2024.

(b) Operating costs, excluding effects of PSCs is a non-GAAP measure. As described above, the reporting of our PSCs creates a difference between reported operating costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel operating costs. These amounts represent our operating costs after adjusting for this difference.

The following table reconciles our average net production to our average gross production (which includes production from the fields we operate and our share of production from fields operated by others) for the periods presented:

	Year ended December 31,		
	2024	2023	2022
		(MBoe/d)	
Average Net Production	110	86	91
Partners' share under PSCs	6	7	8
Working interest and royalty holders' share	9	7	6
Other	4	1	1
Average Gross Production	129	101	106

Estimated Proved Reserves and Future Net Cash Flows

The following tables summarize our estimated proved oil (including condensate), NGLs and natural gas reserves and PV-10 as of December 31, 2024. Our estimated volumes and cash flows were calculated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Prices), unless prices were defined by contractual arrangements. For oil volumes, the average Brent spot price of $80.42 per barrel was adjusted for gravity, quality and transportation costs. For natural gas volumes, the average NYMEX gas price of $2.13 per MMBtu was adjusted for energy content, transportation fees and market differentials. All prices are held constant throughout the lives of the properties. The average realized prices for estimating our proved reserves as of December 31, 2024 were $77.91 per barrel for oil, $46.73 per barrel for NGLs and $2.71 per Mcf for natural gas.

Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. Refer to *Part II, Item 8 – Financial Statements, Supplemental Oil and Gas Information* for additional information on our proved reserves.

	As of December 31, 2024				
	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total
Proved developed reserves					
Oil (MMBbl)	314	77	—	21	412
NGLs (MMBbl)	31	—	—	1	32
Natural Gas (Bcf)	347	5	15	3	370
Total (MMBoe)[(a)]	403	78	3	22	506
Proved undeveloped reserves					
Oil (MMBbl)	30	—	—	1	31
NGLs (MMBbl)	2	—	—	—	2
Natural Gas (Bcf)	36	—	3	—	39
Total (MMBoe)	38	—	—	1	39
Total proved reserves					
Oil (MMBbl)	344	77	—	22	443
NGLs (MMBbl)	33	—	—	1	34
Natural Gas (Bcf)	383	5	18	3	409
Total (MMBoe)	441	78	3	23	545
Reserves to production ratio (years)[(b)]	14	13	3	12	14

(a) As of December 31, 2024, approximately 8% of proved developed oil reserves, 7% of proved developed NGLs reserves, 9% of proved developed natural gas reserves and, overall, 8% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

(b) Calculated as total proved reserves as of December 31, 2024 divided by total production for the year ended December 31, 2024.

Changes to Proved Reserves

The components of the changes to our proved reserves during the year ended December 31, 2024 were as follows:

	San Joaquin Basin	Los Angeles Basin[(a)]	Sacramento Basin	Other Basins	Total
			(MMBoe)		
Balance at December 31, 2023	276	92	9	—	377
Revisions related to price	(9)	(2)	(4)	—	(15)
Revisions related to performance	(1)	4	(1)	—	2
Revisions due to California regulatory challenges	(6)	(10)	—	—	(16)
Improved recovery	1	—	—	—	1
Acquisitions	211	—	—	25	236
Production	(31)	(6)	(1)	(2)	(40)
Balance at December 31, 2024	441	78	3	23	545

(a) Includes proved reserves related to PSCs of 62 MMBoe and 76 MMBoe at December 31, 2024 and 2023, respectively.

Revisions related to price – We had net negative price-related revisions of 15 MMBoe primarily resulting from lower average realized prices in 2024 as compared to 2023, including lower natural gas realizations in 2024. These revisions included negative price-related revisions of 18 MMBoe, which were partially offset by 3 MMBoe of positive revisions from operating cost efficiencies.

Revisions related to performance – We had 2 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 12 MMBoe and negative performance-related revisions of 10 MMBoe. Our positive performance-related revisions primarily related to better-than-expected well performance. Our negative performance-related revisions primarily were due to lower overall expected recovery in the San Joaquin basin.

Revisions due to California regulatory challenges – We had 7 MMBoe of negative revisions due to lower maximum allowable surface injection pressure at the Wilmington field in the Los Angeles basin. We had 1 MMBoe of negative revisions due to the impact of AB 2716 at the Inglewood field in the Los Angeles basin. We had 2 MMBoe of negative revisions due to the retraction of the SB 1137 referendum and our analysis of sensitive receptor designations. The majority of these revisions were located in the Los Angeles Basin. We had 6 MMBoe of negative revisions associated with delays in obtaining new well drilling permits. The majority of the revisions related to permits was in the San Joaquin basin. See *Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Improved recovery – We added 1 MMBoe related to increased well performance in certain areas in the San Joaquin basin.

Acquisitions – We acquired 236 MMBoe in the Aera Merger. See Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger for more information on this transaction.

Proved Undeveloped Reserves

The total changes to our proved undeveloped reserves during the year ended December 31, 2024 were as follows:

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total
			(MMBoe)		
Balance at December 31, 2023	41	4	1	—	46
Revisions related to price	(3)	—	—	—	(3)
Revisions related to performance	(4)	—	(1)	—	(5)
Revisions due to California regulatory challenges	(6)	(4)	—	—	(10)
Improved recovery	1	—	—	—	1
Acquisitions	11	—	—	1	12
Transfers to proved developed reserves	(2)	—	—	—	(2)
Balance at December 31, 2024	38	—	—	1	39

Revisions related to price – We had 3 MMBoe of net negative price-related revisions primarily resulting from lower average realized prices in 2024 as compared to 2023, including lower natural gas realizations in 2024. Our negative price revisions of 3 MMBoe were partially offset by insignificant positive revisions from operating cost efficiencies.

Revisions related to performance – We had 5 MMBoe of net negative performance-related revisions due to low performance of recent drilling and subsequent type curve updates in the San Joaquin basin. Negative performance-revisions of 5 MMBoe were partially offset by insignificant positive revisions related to well performance in the San Joaquin basin.

Revisions due to California regulatory challenges – We removed 10 MMBoe from proved undeveloped reserves due to the regulatory changes discussed above. The majority of these revisions were located in the San Joaquin basin and the Los Angeles basin. See *Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

Improved recovery – We added 1 MMBoe related to increased well performance in certain areas in the San Joaquin basin.

Acquisitions – We acquired 12 MMBoe in the Aera Merger. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger* for more information on this transaction.

Transfers to proved developed reserves – We converted 2 MMBoe of proved undeveloped reserves to proved developed reserves in the Los Angeles basin. This resulted in a conversion rate of 4% of our beginning-of-year proved undeveloped reserves, with an investment of $44 million in drilling and completion capital. We plan to continue drilling sidetracks in 2025 and, subject to the availability of permits, expect to increase our rig count in the second half of the year. We believe that we will be able to develop all year-end 2024 proved undeveloped reserves within five years of their original booking date. For more information on the 2025 Capital Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Uses of Cash* and for more information on permitting, refer to *Regulation of the Industries in Which We Operate, Regulations of Exploration and Production Activities*.

PV-10 and Standardized Measure

PV-10 of cash flows is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and operating costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC Prices. Calculation of PV-10 does not give effect to derivative transactions. Our PV-10 is computed on the same basis as our standardized measures of future net cash flows, the most comparable measure under GAAP, but does not include the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

	As of December 31, 2024
	(in millions)
Standardized measure of discounted future net cash flows	$ 6,702
Present value of future income taxes discounted at 10%	2,175
PV-10 of cash flows[a]	$ 8,877

(a) The average realized prices for estimating our PV-10 of cash flow as of December 31, 2024 were $77.91 per barrel for oil, $46.73 per barrel for NGLs and $2.71 per Mcf for natural gas.

Reserves Evaluation and Review Process

Our estimates of proved reserves and related discounted future net cash flows as of December 31, 2024 were made by our technical personnel, comprised of reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management's funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Operating and capital costs are forecast using the current cost environment applied to expectations of future operating and development activities related to the proved reserves. See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Estimates* for further discussion of uncertainties inherent in the reserve estimates.

Proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods, for which the incremental cost of any additional required investment is relatively minor. Proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Our Director of Reserves is the technical person who is primarily responsible for overseeing the preparation of our reserves estimates in compliance with the SEC rules and regulations. He has over 15 years of experience in the upstream oil and gas industry, with projects ranging from appraisal of primary production reservoirs to enhanced oil recovery floods. He holds a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, to review and approve our oil and natural gas reserves for 2024. The Reserves Committee annually reports its findings to the Audit Committee.

Audits of Reserves Estimates

Netherland, Sewell & Associates, Inc. (NSAI) was engaged to provide independent audits of our reserves estimates for our fields. For the year ended December 31, 2024, NSAI audited 85% of our total proved reserves.

Our independent reserve engineers examined the assumptions underlying our reserves estimates, adequacy and quality of our work product and estimates of future production rates. They also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, they developed their own independent estimates of reserves for those fields that they audited. When compared on a field-by-field basis, some of our estimates were greater and some were less than the estimates of our independent reserve engineers. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our estimates and those of our independent reserve engineers are to be expected. The aggregate difference between our estimates and those of the independent reserve engineers was less than 10%, which was within the Society of Petroleum Engineers (SPE) acceptable tolerance.

In the conduct of the reserves audits, our independent reserve engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if anything came to the attention of our independent auditors that brought into question the validity or sufficiency of any such information or data, they would not rely on such information or data until they had resolved their questions relating thereto or had independently verified such information or data. Our independent reserve engineers determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC as well as the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. Our independent reserve engineers issued an unqualified audit opinion on the applicable portions of our proved reserves as of December 31, 2024, which is attached as Exhibit 99.1 to this Form 10-K and incorporated herein by reference.

NSAI qualifications – The primary technical engineer responsible for our audit is a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. The primary geologist for our audit is a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience.

Drilling Statistics

The following table sets forth information on our net exploration and development wells drilled and completed during the periods indicated, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. We refer to gross wells as the total number of wells in which interests are owned, including outside operated wells. Net wells represent wells reduced to our fractional interest. For information on our 2025 capital program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Uses of Cash* and for information on the California regulatory environment and our ability to obtain permits, see *Regulation of the Industries in Which We Operate*.

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total Net Wells
2024					
Productive					
Exploratory	—	—	—	—	—
Development	8.0	—	—	—	8.0
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2023					
Productive					
Exploratory	—	—	—	—	—
Development	4.0	26.5	—	—	30.5
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—
2022					
Productive					
Exploratory	—	—	—	—	—
Development	114.3	35.0	—	—	149.3
Dry					
Exploratory	—	—	—	—	—
Development	—	—	—	—	—

The following table sets forth information on our development wells where drilling was either in progress or pending completion as of December 31, 2024.

	San Joaquin Basin	Los Angeles Basin	Sacramento Basin	Other Basins	Total Net Wells
Gross	2.0	—	—	—	2.0
Net	2.0	—	—	—	2.0

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce at a reasonable rate of return. Our average working interest in our producing wells was 97% as of December 31, 2024. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2024, excluding wells that have been idle for more than five years:

	As of December 31, 2024			
	Productive Oil Wells		Productive Natural Gas Wells	
	Gross[(a)]	Net[(b)]	Gross[(a)]	Net[(b)]
San Joaquin Basin	15,056	14,712	110	108
Los Angeles Basin	1,709	1,617	—	—
Sacramento Basin	—	—	253	237
Other Basins	629	629	597	558
Total	17,394	16,958	960	903
Multiple completion wells included in the total above	179	176	16	13

(a) The total number of wells in which interests are owned.
(b) Net wells include wells reduced to our fractional interest.

Exploration Inventory

We have had minimal investment in exploration activity in recent years, and our 2025 capital plan does not allocate any capital towards exploration drilling.

Marketing Arrangements

Our oil, natural gas and NGL sales for the years ended December 31, 2024, 2023 and 2022 are shown in the table below. For more information on our revenues, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 15 Revenue.*

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
Oil	$ 2,255	$ 1,534	$ 1,968
NGLs	186	198	264
Natural gas	96	423	411
Oil, natural gas and NGL sales	$ 2,537	$ 2,155	$ 2,643

Crude Oil

We sell nearly all of our crude oil to California refiners. A majority of our crude oil production is connected to third-party pipelines and California refining markets via our gathering systems. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements.

The prices paid by California refiners have been typically based on local postings that are closely tied to Brent prices. Beginning in 2025, the marketing arrangements for the majority of our production will no longer rely on local postings but will instead be based directly on Brent prices subject to applicable adjustments. International waterborne-based Brent prices are relevant because there is limited crude pipeline infrastructure available to transport crude overland from other parts of the United States into California. We believe that these limitations will continue to contribute to higher realizations in California than most other U.S. oil markets for comparable grades.

In October 2024, Phillips 66 announced that it plans to close its Wilmington refinery in Los Angeles in late 2025. For the six-month period following the Aera Merger, we sold approximately 8% of our production to this refinery. Following the closure of the Phillips 66 refinery, there will be seven remaining major petroleum refineries in California, each of which have a refining capacity greater than 75,000 barrels per day. Due to the significant excess of refining capacity in California versus the quantity of crude oil produced locally, we do not expect the closure of this refinery to affect our ability to market our crude oil production, or to negatively impact our price realizations.

Natural Gas

We sell all of our natural gas not used in our operations into the California market. A majority of these sales are made at index based prices. Natural gas prices and differentials are strongly affected by local market fundamentals, such as storage capacity and the availability of transportation capacity between the market and producing areas. Transportation capacity influences prices because California imports more than 90% of its natural gas from other states and Canada.

In addition to selling natural gas, we also use natural gas in steam generation for our steamfloods and for power generation. We have entered into derivative contracts to provide price protection for the purchase of natural gas used in our operations. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our natural gas derivative contracts.

NGLs

NGL prices vary by liquid type and realizations are closely correlated to the different commodity prices to which they relate. Prices can also fluctuate due to the demand for certain chemical products (for which NGLs are used as feedstock) and due to infrastructure constraints and seasonality. Finally, our results are also affected by the performance of our natural gas-processing plants. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the remaining products as NGLs. The efficiency with which we extract liquids from the wet gas stream affects our production volumes and operating results. Our natural gas-processing plants also facilitate access to third-party delivery points near the Elk Hills field.

We currently have a ship-or-pay pipeline transportation contract for approximately 6,000 barrels per day of NGLs through March 2026. Our contract to transport NGLs requires us to cash settle any shortfall between the contractual throughput minimums and volumes actually shipped. We have met all our throughput minimums under this contract for the periods presented.

Delivery Commitments

We have commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs, including delivery commitments obtained as part of the Aera Merger. As of December 31, 2024, we had the following delivery commitments as shown in the table below.

	2025	2026	2027	2028	2029
Oil (MMBbl)	35	27	20	3	—
NGL (MMBbl)	1	—	—	—	—
Natural gas (Bcf)	23	—	—	—	—

We expect to fulfill our delivery commitments predominantly from our production and to a lesser extent from third party volumes acquired in connection with our marketing activities. We typically enter into index-based contracts with prices set at the time of delivery.

Our Principal Customers

We sell crude oil, natural gas and NGLs to California refineries, marketers and other purchasers that have access to transportation and storage facilities. Our ability to sell our products can be affected by a variety of factors that are beyond our control. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of our Business, Summary of Significant Accounting Policies and Other* for more information on our customers.

Title to Properties

As is customary in the oil and natural gas industry for acquired properties, we initially conduct a high-level review of the title to our properties at the time of acquisition. Individual properties may be subject to ordinary course burdens that we believe do not materially interfere with the use or affect the value of such properties. Burdens on properties may include customary royalty or net profits interests, liens incident to operating agreements and tax obligations or duties under applicable laws, or development and abandonment obligations, among other items. Prior to the commencement of drilling operations on those properties, we typically conduct a more thorough title examination and may perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. For additional information on properties that secure our debt, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt.*

Competition

Our competitors are primarily other exploration and production companies that produce oil, natural gas and NGLs. We compete locally against independent producers and a major international oil company which operate in California. We also compete with foreign oil and gas companies since California imports approximately 75% of the oil it consumes and approximately 90% of its natural gas needs. We believe that our proximity to the California refineries gives us a competitive advantage over importers due to lower transportation costs. Further, California refineries are generally designed to process crude with the unique characteristics which are similar to our produced oil. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using our firm capacity contracts.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. The regulatory environment in California could negatively impact the number of oil field service providers, drilling and workover rigs, pipe and other oil field equipment in the state. However, we have not experienced shortages or delays in the delivery of materials or services from our vendors.

Carbon Management Segment

Our carbon management segment, which we refer to as Carbon TerraVault, pursues the development of carbon capture and sequestration projects. We expect that our Carbon TerraVault CCS projects will inject CO_2 captured from industrial, power, agriculture and other emissions sources into subsurface reservoirs and permanently store CO_2 deep underground. We also expect to invest in projects that rely on CCS technology in connection with reducing our own emissions. In addition, we may participate in the development of projects that are the source of these CO_2 emissions.

EPA Class VI Permits

We are in the early stages of developing several CCS projects in California. In December 2024, the EPA issued Class VI permits, the first permits issued in California, for underground injection and storage of CO_2 into the 26R reservoir which is located at our Elk Hills field. The permits became effective on February 6, 2025. The 26R reservoir is part of our joint venture with Brookfield as discussed further below.

We have submitted permit applications with the EPA for another permanent sequestration project at our Elk Hills field, four permanent sequestration projects in the Sacramento Basin and one permanent sequestration project in Central California that are under review by the EPA. We acquired one permit application with the EPA for sequestration projects in the Belridge field as part of the Aera Merger. Our permit applications are subject to additional review and approval by the EPA.

CCS Projects

In January 2025, we announced the approval of the installation of carbon capture equipment at our cryogenic gas processing facility at the Elk Hills field which will remove CO_2 from inlet gas and which will be injected into the nearby 26R storage reservoir owned by the Carbon TerraVault JV. We expect this project will increase operational efficiency of the cryogenic gas processing plant, improving propane recovery, and reduce the carbon intensity of the electricity generated from our Elk Hills Power Plant. Our expected capital investment for this project is $14 million to $18 million with operations expected to commence in late 2025. We are also evaluating the feasibility of developing a carbon capture system for our 550-megawatt Elk Hills power plant (CalCapture). We continue to work with a consortium of industry participants to advance the development of a direct air capture hub to be located in Kern County and have been selected for a U.S. Department of Energy grant for this project as discussed further below.

We expect that the size and scope of our projects providing these and similar services and the related capital spent on such projects will continue to grow given our strategy of expansion into these services and the development of our carbon management segment. For more information about the risks involved in our carbon management segment, see *Part I, Item 1A – Risk Factors.*

Carbon TerraVault JV

In August 2022, we entered into a joint venture with Brookfield. We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Our initial contribution included rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage. Brookfield has contributed $92 million to date. The remaining amount of Brookfield's initial investment will depend on the amount of storage capacity that is permitted subject to certain contractual adjustments. The parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met. As noted above, on December 30, 2024, the EPA issued Class VI permits to the Carbon TerraVault JV for the CTV I storage site.

Both Brookfield and CRC have granted the other party a right to participate in projects that involve the capture, transportation and storage of CO_2 in California. These projects may be developed throughout the Carbon TerraVault JV or other joint ventures. This right expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the investment committee of the Carbon TerraVault JV for storage projects representing in excess of 5 million metric tons per annum (MMTPA) in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of $500 million (unless Brookfield elects to increase its commitment). The non-presenting party has the option to accept, decline or defer its decision to participate. If the decision is deferred, then the presenting party may continue to pursue development; however during this time and prior to a final investment decision, the non-presenting party may elect to participate provided they pay their share of the project development costs incurred up to that point. The joint venture does not have a definitive term and terminates upon either party holding all of the ownership interests in the joint venture.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our Carbon TerraVault JV.

Competition

In our carbon management segment, we compete with other potential storage providers to acquire and develop storage reservoirs and enter into agreements with existing and future emission sources.

Infrastructure

Our infrastructure includes the plants and facilities shown in the table below, inclusive of our assets used in power generation and oil and natural gas operations.

Description	Quantity	Unit	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Processing Plants	5	MMcf/d	335	10	345
Power Plants[(a)]	7	MW	791	—	791
Steam Generators/Plants	156	MBbl/d	380	—	380
Compressors	1,231	MHp	346	31	377
Water Management Systems		MBw/d	3,422	420	3,842
Water Softeners	80	MBw/d	250	—	250
Oil and NGL Storage		MBbls	689	46	735
Pipelines		Miles			>11,000

(a) Includes 120 MW attributable to our 50% interest in the Midway Sunset Power Plant. Does not include the Long Beach Unit Power Plant described below or microturbines that generate limited power.

Power Plants

We own and/or operate the following power generation facilities:

Elk Hills Power Plant – We own a 550 MW combined-cycle cogeneration power plant, located adjacent to the Elk Hills natural gas processing facility. Approximately a third of the electricity generated from this plant is used in our oil and natural gas operations at Elk Hills. The balance of the power capacity is currently marketed into the resource adequacy market with excess energy produced being sold into the CAISO wholesale market.

Midway Sunset Power Plant – Following the Aera Merger, we own a 50% interest in a 240 MW cogeneration power plant located in the Midway Sunset field in Kern County, California and the remaining 50% is held by San Joaquin Energy Company, a subsidiary of NRG Energy, Inc. Our investment in this joint venture is accounted for using the equity method of accounting as discussed in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions.* The electricity generated by this plant is sold to CAISO and the facility also participates in the resource adequacy capacity market.

Belridge Power Plant – Following the Aera Merger, we own a 62 MW cogeneration power plant located in the Belridge field in Kern County, California. The electricity generated by this plant is used in our operations.

Long Beach Unit Power Plant – We operate a 48 MW power generating facility that is owned by the Long Beach Unit in the Wilmington field. The electricity generated by this plant is used in our operations.

In addition, we own and/or operate a number of smaller gas-fired power plants that are primarily used to generate power for our oil and natural gas operations.

Other Infrastructure Assets Used in Oil and Natural Gas Segment

Gas processing infrastructure used in our oil and gas segment includes the Elk Hills cryogenic gas plant with a capacity of 200 MMcf/d of inlet gas and one low temperature separation plant used as a backup facility. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to various North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our natural gas processing facilities for NGL sales to third parties. We own, control and operate water management and steam-generation infrastructure. We soften and self-supply water to generate steam, reducing our operating costs. This is integral to our operations in the San Joaquin basin and supports our high-margin oil fields. Our tank storage capacity throughout California gives us flexibility for a period of time to store crude oil and NGLs, allowing us to continue production and avoid or delay any field shutdowns in the event of temporary power, pipeline or other shutdowns. Our pipelines are dedicated almost entirely to collecting our oil and natural gas production and are in close proximity to field-specific facilities such as tank farms or central processing sites. Our oil pipelines connect to multiple third-party transportation pipelines. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems.

Human Capital Management

We had approximately 1,550 employees as of December 31, 2024 as compared to approximately 970 as of December 31, 2023, all of whom were located in the United States. The significant growth in headcount was due to the employees who joined CRC following the Aera Merger. Approximately 240 of our employees are covered by a collective bargaining agreement. We also utilize the services of many third-party contractors throughout our operations.

Development

Employee development opportunities are provided to enhance leadership development and expand career opportunities. Our employees undergo mandatory annual training on our policies including health and safety, business ethics, harassment, IT security and others. In addition to training, our employees receive regular performance and career development discussions from their direct managers. All employees receive annual performance reviews.

Diversity

Our goal is to foster an open and diverse culture and we are committed to advancing a workplace culture inclusive of all backgrounds and perspectives. We believe this encourages workforce engagement and leads to more thoughtful and innovative business decisions.

Safety

Our unwavering commitment to health, safety and the environment defines how we operate our business. We prepare our workforce to work safely through comprehensive training, safe work practices, technology and rigorous maintenance and asset integrity programs. Each year, we set thresholds for TRIR and spill prevention as quantitative metrics that directly impact incentive compensation for all of our employees. We achieved a 99.999% oil spill prevention rate in 2024 and registered a workforce TRIR of 0.39 (including Aera's results following the Aera Merger). We have achieved exemplary safety performance over the last several years by promoting a culture of safety where all employees, contractors and vendors are empowered with Stop Work Authority to cease any activity – without repercussions – to prevent a safety or environmental accident.

Engagement and Retention

We survey our employees annually to ensure employee sentiment is collected and heard each year allowing us to assess engagement levels and drivers to determine areas of improvement to enhance engagement and retention. The results of the engagement surveys are reviewed by senior management and our Board of Directors. Senior leadership also hosts regular townhalls so employees can engage with them through question-and-answer sessions.

Regulation of the Industries in Which We Operate

Our operations are subject to a wide range of federal, state and local laws and regulations. Those that specifically relate to oil and natural gas exploration and production and carbon sequestration, utilization and storage are described in this section. CalGEM is the primary regulator of the oil and natural gas production industry in California. The State Lands Commission provides additional administration of the state's surface and mineral interests.

Regulation of Exploration and Production Activities

Well Permitting

During 2024, we continued to experience delays from CalGEM with respect to obtaining new well, sidetrack, deepening and workover permits for our operations. These delays are a result of various factors, including more stringent environmental reviews in connection with permitting, limited resources at CalGEM, and policy directives that are outside of our control.

During 2024, we (including our Aera subsidiary) received well permits for 799 workovers and 145 sidetracks.

New Production Permits

Since December 2022, CalGEM has issued a limited number of permits to other operators for new production wells in California. In 2024, CalGEM issued 77 new well permits to other operators, 40 of which were for oil and natural gas production wells and 37 of which were for injection and observation wells. These permits were issued for wells outside of Kern County or within Kern County but in reliance on authority other than the Kern County EIR discussed below.

We continue to pursue an alternative path for the permitting of wells in Kern County other than in reliance on the Kern County EIR. We have submitted applications for conditional use permits (CUPs) for projects at our Aera subsidiary's Belridge field and our Kern Front, Elk Hills and Buena Vista fields. Timing for completion of the CUP application processes is difficult to estimate and could extend into the first half of 2026. Our ability to obtain the CUPs is uncertain and we may not be successful in obtaining such permits in a timely manner or at all.

Sidetrack, Deepening and Workover Permits

CalGEM finalized its procedures for the review of permit applications for workovers in December 2023 and its lead agency review process for sidetrack permits in September 2024 and recently resumed evaluation of permits for deepenings. Following the adoption of these procedures, we experienced an increase in the issuance by CalGEM of permits for workovers and sidetracks during the course of 2024. However, the rate of issuance of permits for deepening wells has not increased.

We cannot guarantee that the issues described above or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. Any continuing failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, results of operations and our financial condition. See *Part 1, Item IA – Risk Factors, We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments*.

Kern County EIR Litigation

In 2015 the Kern County Board of Supervisors (i) approved the county's adoption of an ordinance providing for a single proscribed project for the development of oil and natural gas wells in the county by the various operators within their individual fields; and (ii) certified the Environmental Impact Report (EIR) prepared by the county for the project. Following the adoption of the ordinance, the county relied on the certified EIR to satisfy CEQA requirements for the well permits issued under the ordinance.

Our operations in Kern County have been subject to significant uncertainty over the past several years as a result of ongoing challenges to Kern County's ability to rely on the EIR and its subsequent iterations to satisfy CEQA requirements for well permits issued under the ordinance. In December 2015, several groups filed CEQA litigation against Kern County challenging the EIR. These proceedings have resulted in multiple rulings and appeals and the matter remains ongoing. The Trial Court imposed a stay on the issuance of new well permits under the ordinance in June 2022 which has remained in effect throughout most of the litigation and is currently in effect pending resolution of the matter by the Court of Appeals.

On March 7, 2024, the Court of Appeals issued its ruling on challenges made to a revised EIR. As a result, Kern County was directed to (a) prepare a further revised EIR that corrects deficiencies relating to (1) the rejection of agricultural conservation easements as a form of partial mitigation for the conversion of agricultural land, (2) assessment of cancer risks associated with the drilling of multiple wells near sensitive receptors and (3) analysis of water supply impacts; and (b) circulate the further revised EIR for public review and comment, and subsequently certify this revised EIR.

On March 22, 2024, Kern County released a notice of preparation of the further revised EIR. Kern County is expected to circulate a draft for public comment in the first quarter of 2025 and thereafter seek the Trial Court's determination on this EIR's compliance with the ruling of the Court of Appeals, certify this EIR and approve the revised ordinance. After that, the Trial Court would then be able to lift the stay, subject to further potential appeals. If the stay is lifted, new well permitting could resume. However, there is no certainty we will obtain permits on that timeline or at all, or that the Trial Court will approve the certification of the further revised EIR or lift the stay, which could further adversely affect our business, results of operations and financial condition.

As a result of these issues and current lack of permits with respect to our Kern County properties, we plan to operate one active drilling rig within Kern County in the first half of 2025 and have the requisite number of permits in hand to keep that rig active through the end of 2026. We operated one rig in 2024. We plan to begin drilling certain sidetracks under existing sidetrack permits in the first half of 2025 and plan to increase our active rig count in Kern County to two (2) rigs in the second half of 2025. In 2025, approximately $21 million of capital to develop proved reserves relates to drilling and completing sidetracks in Kern County for which we do not presently have a permit. If we are unable to obtain the necessary permits for the development of these wells, we will pursue alternatives for the deployment of this capital. For more information on our 2025 Capital Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Uses of Cash.*

Regulatory Activity

The California Legislature and Governor have significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years through legislation and policy pronouncements. CalGEM's duties now include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs. CalGEM is also required to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators. CalGEM and other state agencies have also significantly revised their regulations, regulatory interpretations and data collection and reporting requirements.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general, including limiting well stimulation, completion or injection activities, imposing setback distances from certain other land uses, or banning such activities outright. Other local governments have also sought to ban natural gas or the transportation of natural gas through their cities. For example, the cities of Brentwood and Antioch have refused to extend the necessary franchise agreements to preserve an existing pipeline that runs through their jurisdictions. In July 2023, one of our subsidiaries submitted an application with the CPUC to convert this pipeline to common carrier status. The application is still pending.

Setbacks and Senate Bill 1137 (SB 1137)

On September 16, 2022, the Governor of California signed Senate Bill No. 1137 which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public and separately imposed a number of potential impact analysis and mitigation and reporting requirements. Senate Bill No. 1137 was stayed during a referendum process that was ultimately withdrawn and finally became effective on June 27, 2024. However, on September 30, 2024, the Governor signed into law Assembly Bill No. 218, which extends the timeline for the implementation of certain initial and future monitoring and reporting requirements until July 1, 2026 and further delays compliance with certain other requirements by up to three years. Assembly Bill. No. 218 does not modify the 3,200-foot setback requirements applicable to new wells, sidetracks, deepenings or workovers.

The majority of our production is in rural areas in the San Joaquin basin and is not affected by Senate Bill No. 1137. In addition to the write-down of reserves previously recorded in 2023, we continue to evaluate the location of projects near setback zones and believe any further reductions to the net present value of our proved undeveloped reserves as a result of the implementation of Senate Bill No. 1137 would be immaterial.

Idle Wells and Assembly Bill 1866 (AB 1866)

This law, effective January 1, 2025, increases the annual fees operators must pay per idle well, depending on how long each well has been idle, and includes a new fee for those wells that have been idle for less than three years. In lieu of the annual fees, operators can instead file an eight-year plan with the State to provide for the management and elimination of their idle wells. This law also increases the minimum percentages of idle wells that operators are required to eliminate each year. The rate at which idle wells must be eliminated varies depending on the number of an operator’s idle wells. Operators must prepare and submit a plan for the elimination of idle wells to CalGEM for approval. We implement robust programs for managing and eliminating idle wells that meet or exceed the requirements of the new law. As a result, we do not expect this new law to have any meaningful impact on our current plans for eliminating idle wells or meaningfully increase fees associated with our idle wells.

Baldwin Hills Conservancy and Assembly Bill 2716 (AB 2716)

This law requires operators to plug “low production wells” located within the boundary of the Baldwin Hills Conservancy in Los Angeles within a certain timeframe or otherwise subjects operators to administrative penalties. A “low-production well” is a well that produced fewer than an average of 15 barrels of oil a day during the past 12 months. We have limited operations and assets within the affected area. As a result, we expect that this law will not have a material adverse effect on either our total production or proved reserves.

Local Regulation and Assembly Bill 3233 (AB 3233)

This law provides local governments with the authority to limit methods for, or even prohibit oil and gas operations or development within their jurisdiction, including with respect to existing operations. Prior to the passage of this law, certain local governments in California, including the City and County of Los Angeles and Monterey County, had attempted to limit oil and gas operations within their jurisdictions and such actions had been challenged and struck down by California courts. However, following the adoption of AB 3233, certain legal challenges previously made to these local actions are no longer valid and it is possible that these or other local governments in California may attempt to pass new or similar restrictions. Future bans or restrictions on production or development by the City of Los Angeles or the counties of Los Angeles and Monterey could impact our production negatively or result in the write-down of our reserves.

For the fiscal year ended December 31, 2024, over 70% of our gross production is located in Kern County, and at this time we are not aware of any local governments within Kern County that are considering materially limiting or otherwise prohibiting oil and gas operations within their jurisdiction. However, it is difficult to predict how local governments in California may choose to exercise their new authority under AB 3233. There may be future legal challenges to AB 3233 and any local ordinances enacted thereunder and we cannot predict whether or not such challenges will be successful.

See *Part 1, Item IA – Risk Factors – We may face increased local restrictions on oil and gas exploration and production operations or even be prohibited from operating in certain areas as a result of recently enacted California legislation*.

Bonding and Assembly Bill 1167 (AB 1167)

On October 7, 2023, the California Governor signed into law Assembly Bill 1167 (AB 1167), which imposes more stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in California, requiring them to file either an individual indemnity bond for single-well or production facility acquisitions, or a blanket indemnity bond for multiple wells or production facilities. Upon signing AB 1167, Governor Newsom called for further legislative changes to these new requirements to mitigate against the potential risk of the implementation of AB 1167 ultimately increasing the number of orphaned idle or low-producing wells in California, although no such changes have yet been announced. We cannot predict what form these changes may ultimately take or if the legislature will act on the Governor’s request. Implementation of this law may lead to the delay or additional costs with respect to certain acquisitions or dispositions, which could impact our ability to grow or explore new strategic areas – or exit others – within California.

Pipeline Transportation

Federal and state pipeline regulations have also been revised by both CalGEM and the Office of the State Fire Marshal over recent years, including requirements relating to integrity management, risk assessments, and spill prevention, amongst others. Additionally, PHMSA has, from time to time, issued new regulations expanding or otherwise revising pipeline integrity requirements. For example, in January 2025, PHMSA released a proposed draft of a final rule that would enhance requirements for detecting and repairing leaks on new and existing natural gas distribution, gas transmission and gas gathering pipelines. Prior to that, in September 2023, PHMSA published a proposed rule that would enhance the safety requirements for gas distribution pipelines and would require updates to distribution integrity management programs, emergency response plans, operations and maintenance manuals, and other safety practices. PHMSA finalized this proposed rule in January 2025.

Water Injection

Our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. During 2024, we entered into discussions with the City of Long Beach and

CalGEM regarding the level of injection well pressure gradient needed to comply with CalGEM's requirements for the protection of underground aquifers, while at the same time mitigating subsidence risks. In July 2024, CalGEM issued a directive to reduce the injection well pressure in a gradual manner and we implemented a five-year injection reduction work plan. The first phase of reduction commenced July 1, 2024 with a second reduction beginning in January 2025. We continue to evaluate the work plan with CalGEM, including any subsidence risk, and the work plan may be adjusted further in the future. Given this uncertainty, it is difficult to predict with accuracy the impact to production and reserves. However, assuming no adjustments to the current work plan, we estimate a negative impact on production of approximately 1 MBoe/d at the end of the 5-year work plan. We also estimate that the net present value of our proved developed reserves would be negatively impacted by less than 1%. These estimates could change materially pending the results of future technical audits.

Activism

Opposition toward oil and gas drilling and development activity has been growing over time. Companies in the oil and gas industry are often the target of efforts to delay or prevent oil and gas development by non-governmental organizations and individuals. This opposition also extends to our carbon management segment as certain activists oppose carbon capture and sequestration efforts by the oil and gas industry. These activists use a variety of tactics that primarily rely on allegations regarding safety, environmental compliance and business practices. At both the state and federal level, these tactics include seeking changes to laws, pressuring governmental agencies to promulgate regulations or engage in rulemaking, or pursuing litigation.

For example, we were recently named a real party in interest in *Center for Biological Diversity v. City of Long Beach, Long Beach City Council, California State Lands Commission, et al.*, a lawsuit brought by an environmental non-governmental organization seeking various remedies on the basis of a purported failure to conduct a CEQA review. In January 2025, the Superior Court of California, County of Los Angeles, denied the claimant's petitions. Following this decision, we do not expect a material adverse effect on our business or operations as a result of this lawsuit, pending the outcome of any appeals.

Separately, for example, in November 2024, environmental groups collectively filed CEQA litigation against Kern County alleging CEQA violations in connection with the County's approval of conditional use permits for our CTV I project at our Elk Hills Field. At this time, we cannot predict the outcome of this challenge with any certainty. Such lawsuits have the potential to delay timely construction of our CCS projects and commencement of operations and could otherwise have a material adverse effect on our business, results of operations and financial condition. Please see *Regulation of Carbon Capture, Sequestration and Storage – CCS Project Permitting* below for additional information.

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and NEPA, among others. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;

- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, and implementation of inspection, monitoring and repair programs to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation and reclamation measures, impose energy efficiency or renewable energy standards on us or users of our products and services, and restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and
- may restrict our rate of oil, NGLs, natural gas and/or electricity production.

These requirements can result in restrictions on our operations. For example, in 2014, at the request of the EPA, CalGEM commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the Safe Drinking Water Act. In 2015, the state set deadlines to obtain the EPA’s confirmation of aquifer exemptions under the Safe Drinking Water Act in certain formations in certain fields. During the review, the State has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. The State continues to work with EPA to resolve these issues. The aquifer exemption process has slowed in part due to the determination by CalGEM and the State Water Resources Control Board that certain of the remaining applications require additional “conduit analysis” to ensure that injected fluid will not escape from the intended area of subsurface confinement as well as EPA delays. Of the 30 original aquifer exemption proposals addressing permitted injection into a potential underground source of drinking water, 22 have been approved by EPA, with eight applications outstanding. In connection with legal challenges filed against the State by industry stakeholders, the Kern County Superior Court has issued an order generally barring the blanket enforcement of CalGEM’s aquifer exemption regulations mandating grant of an aquifer exemption as a precondition to continued injection activities.

At the federal level, recent modifications to regulations implementing NEPA may impose additional restrictions on oil and natural gas activities on federal lands. In October 2021, the Biden Administration announced three significant changes to a 2020 rule finalized under the Trump Administration. These changes included (i) authorizing agencies to consider the direct, indirect and cumulative effects of major federal actions including upstream and downstream impacts of fossil fuel projects; (ii) allowing agencies to determine the purpose and need of a project (thereby allowing consideration of less-harmful alternatives); and (iii) affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council of Environmental Quality (CEQ) regulations, so as to meet the agencies' and public's need. To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes—"Phase I" of the Biden Administration's two-phased approach to modifying NEPA. In May 2024—"Phase 2"—the CEQ issued a final rule revising the implementing regulations of the procedural provisions of NEPA and implementing amendments to NEPA included in the Fiscal Responsibility Act of 2023. The final rule was challenged by various states and the litigation remains ongoing. More recently, in November 2024, the U.S. Court of Appeals for the D.C. Circuit held that the CEQ lacks authority to issue NEPA regulations. Additionally, the current administration recently signed an energy-related Executive Order which included ordering the CEQ to propose rescinding its NEPA regulations. As a result, there is currently significant uncertainty with respect to the scope of environmental analysis required under NEPA.

There is also uncertainty surrounding the disbursement of federal funding. On January 20, 2025, an Executive Order was issued which paused distribution of federal funds appropriated through the Inflation Reduction Act (IRA) or the Infrastructure Investment and Jobs Act. The pause was aimed at providing time to review the processes, policies and issuance of various grants, loans, contracts or financial disbursements of appropriated funds but did not modify the IRA statutory language with respect to federal income tax credits. However, on January 29, 2025, the White House Office of Management and Budget rescinded the freezing of federal grants and loans, although not its efforts to review the processes with respect to federal spending. Although we are in receipt of small funding awards from the Department of Energy, many of our counterparts with which we are co-developing projects are dependent on much larger awards and loans. Any disruption, delay or withdrawal of federal funding could result in delays with respect to the development and timely completion of such projects or otherwise render them uneconomic, thereby adversely affecting our ability to pursue such projects.

In addition, due to the risk of future drought conditions in California, water districts and the State government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Water management, including our ability to recycle, reuse and dispose of produced water and our access to water supplies from third-party sources, in each case at a reasonable cost, in a timely manner and in compliance with applicable laws, regulations and permits, is an essential component of our operations to produce crude oil, natural gas and NGLs economically and in commercial quantities. As such, any limitations or restrictions on wastewater disposal or water availability could have an adverse impact on our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, waterflooding, steamflooding and well drilling, completion and stimulation. We also provide reclaimed produced water to certain agricultural water districts. We also use supplied water from various local and regional sources, particularly for power plants and steam generation. We are a net freshwater supplier to the state. While our production to date has not been impacted by restrictions on access to third-party water sources, we cannot guarantee that there may not be restrictions in the future.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Regulation of Carbon Capture, Sequestration and Storage

Unitization and Pipelines

On September 16, 2022, the Governor of California signed Senate Bill No. 905 into law, which contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Senate Bill No. 905 also provides for a unified permitting process to simplify the permitting process for CCS projects, although this will be optional for project applicants. Additionally, the law contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California. The California Air Resources Board has been tasked with developing this proposed framework and this work is still pending at this time. We believe that our Carbon TerraVault projects will continue to be developed on a timeline consistent with our initial expectations as these initial projects are not reliant on the unitization or permitting regulations being developed under Senate Bill No. 905.

Senate Bill No. 905 provides that pipelines may be used to transport carbon dioxide to or from a carbon dioxide capture, removal or sequestration project only upon conclusion of PHMSA's rulemaking strengthening safety requirements for carbon dioxide pipelines. Although PHMSA released a notice of proposed rulemaking to this effect in early January 2025, it has not yet been published in the Federal Register and its disposition is uncertain at this time following the change in U.S. presidential administrations. Certain Carbon TerraVault projects are expected to be constructed on sites directly above underground storage facilities and would not be impacted by Senate Bill No. 905 or PHMSA's rulemaking. For those Carbon TerraVault projects that do rely on transportation of CO_2, however, the terms of these final pipeline safety regulations may impair or prohibit our ability to timely pursue future CCS projects that rely on the transportation of CO_2.

CCS Project Permitting

On October 21, 2024, the Kern County Board of Supervisors approved the issuance of the conditional use permits and certified the EIR for our first CCS project, Carbon TerraVault I (CTV I). On November 22, 2024, a group of non-governmental organizations filed a lawsuit against the County of Kern and its Board of Supervisors in Kern County Superior Court, challenging the Board of Supervisors' certification of the EIR for non-compliance with CEQA. In addition to challenging the EIR, the Petitioners have indicated that they intend to seek injunctive relief for a stay of the project but have not yet sought such relief. At this time, we cannot predict the outcome of this litigation with certainty. Such lawsuits have the potential to delay timely construction and commencement of operations at CTV I and could otherwise have a material adverse effect on our carbon management business and its prospects.

On December 31, 2024, the EPA issued four Class VI underground injection control (UIC) permits for the construction and operation of four CO_2 injection wells at the site of the CTV I 26R underground CO_2 storage reservoir at our Elk Hills Field. Per EPA rules, the EPA opened a 30-day period during which certain persons could make limited petitions regarding the permits. No person filed a petition for review or administrative review prior to the January 30, 2025 deadline. As a result, the EPA's permit decision became effective February 3, 2025.

We currently have 7 Class VI permit applications relating to our carbon management segment pending with the EPA in different stages of the permitting process. We expect a final decision on Class VI UIC permits for our CTV I A1-A2 underground CO_2 storage reservoir at our Elk Hills Field in the second half of 2025. We cannot guarantee the ultimate timing of EPA's approval of the Class VI UIC permits for CTV I A1-A2 or any of our other projects, or that those permits will not be challenged, and cannot guarantee how these matters could ultimately delay or otherwise adversely impact our ability to timely execute our CCS projects.

Federal Tax Credits

The Inflation Reduction Act enhanced existing credits for the capture and sequestration of carbon oxide (45Q credit) by increasing the size of the maximum credit to $85 per metric ton of qualified carbon oxide when such carbon oxide is captured from industrial and power generation facilities and to $180 per metric ton of carbon oxide when a direct air capture facility is utilized to capture such carbon oxide, and, in each case, when such captured carbon oxide is disposed of by the taxpayer in secure geological storage. The Inflation Reduction Act also extended the date for when qualifying facilities must begin construction to before January 1, 2033. Further, a direct pay option for the 45Q credit (for a limited five-year period) was added, and the Inflation Reduction Act provides an option to monetize the 45Q credit through a sale of the 45Q credit to another taxpayer. These additional energy-related tax incentives are effective for new projects beginning on January 1, 2023, and enhance the economics for development of CCS projects in California. The accessibility of direct pay, tax equity financing, and the credit transfers market for 45Q credits provided under the Inflation Reduction Act is still developing, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45Q credit exist.

The Inflation Reduction Act also incentivizes the development of clean hydrogen production projects through the clean hydrogen production tax credit under section 45V of the Code (45V credit). The credit amount is up to $3 per kilogram multiplied by an applicable percentage for clean hydrogen for a ten-year period beginning when a qualified facility is placed in service. On January 10, 2025, the IRS and Treasury released final regulations under section 45V. The final regulations provide rules for determining lifecycle greenhouse gas emissions rates resulting from hydrogen production processes; petitioning for provisional emissions rates; verifying production and sale or use of clean hydrogen; modifying or retrofitting existing qualified clean hydrogen production facilities; using electricity from certain renewable or zero-emissions sources to produce qualified clean hydrogen; and electing to treat part of a specified clean hydrogen production facility instead as property eligible for the energy credit.

The amount of the available 45V credit from which we may directly or indirectly benefit in connection with our Carbon TerraVault business will depend on our ability to satisfy certain requirements and obtain certain emissions rate results under the most recent 45V credit Greenhouse Gasses, Regulated Emissions, and Energy Use in Transportation (45VH2-GREET) model or a petition for a provisional emissions rate. The final regulations impose certain requirements, restrictions and limitations that may eliminate or reduce the amount of the credit available to us (or our partners), which may impact our ability to successfully develop clean hydrogen production projects. Moreover, the accessibility of direct pay, tax equity financing, and the credit transfers market for 45V credits provided under the Inflation Reduction Act is still developing, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45V credit still exist.

The current administration recently signed several Executive Orders reversing, revoking or rescinding many climate-related actions and has expressed a desire to make modifications to the Inflation Reduction Act. The enactment of any legislation that reduces or eliminates 45Q credits or 45V credits could have an adverse effect on the development of our carbon management business and its prospects. For more information, see *Part 1, Item IA – Risk Factors – Risks Related to Carbon TerraVault and Our Carbon Management Segment, Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may not currently be sufficient for our Carbon TerraVault business and other CCS projects to be economical, may not be fully realized, or could be changed or terminated.*

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track, mitigate and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy or feedstocks. While in office, President Biden issued several executive orders on climate change. The EPA finalized methane emissions standards for new, modified and existing oil and natural gas: required reporting of annual GHG emissions from oil and natural gas exploration and production, power plants and natural gas processing plants; gathering and boosting compression and pipeline facilities; and certain completions and workovers; incorporation of measures to reduce GHG emissions in permits for certain facilities; and restriction of GHG emissions from certain mobile sources. However, upon the first days in office, the current administration signed several Executive Orders reversing, revoking or rescinding many climate-related actions and it remains to be seen how such Executive Orders may impact our business and what may result from any litigation, administrative or legislative actions relating to such Executive Orders.

Separately, California has adopted stringent laws and regulations to reduce GHG emissions and may continue to adopt more. The current state laws and regulations:

- established a “cap-and-trade” program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the cap-and-trade program currently expires;
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of natural gas, propane and liquid transportation fuels sold for use in California;
- established a low carbon fuel standard (LCFS) and associated tradable credits that require a progressively lower carbon intensity of the state’s fuel supply than baseline gasoline and diesel fuels, and provide a mechanism to generate LCFS credits through innovative crude oil production methods such as those employing solar or wind energy or carbon capture and sequestration;
- mandated that California derive 60% of its electricity for retail customers from renewable resources by 2030;
- established a policy to derive all of California’s retail electricity from renewable or “zero-carbon” resources by 2045, subject to required evaluation of the feasibility by state agencies;
- imposed state goals to double the energy efficiency of buildings by 2030 and to reduce emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030; and
- mandated that all new single family and low–rise multifamily housing construction in California include rooftop solar systems or direct connection to a state–approved community solar system.

In November 2024, CARB finalized amendments to the LCFS Regulation which included increasing 2030 carbon intensity (CI) targets from 20% to 30% and extending CI reductions to 90% by 2045. Additional updates include additional funding of zero-emission vehicle charging and hydrogen fueling infrastructure, amongst other matters. The final rulemaking package was sent to the Office of Administrative Law in January 2025. However, in February 2025, the Office of Administrative Law issued a Notice of Disapproval to CARB, citing clarity and incorrect procedure as grounds for its disapproval. CARB may resubmit the finalized amendments after resolving the identified issues.

The amendments also excluded clean hydrogen produced using CCS from the definition of “Renewable Hydrogen”. Clean hydrogen produced using CCS comes primarily from natural gas using a steam reformation process, which brings together natural gas and heated water in the form of steam. The output is hydrogen. Carbon dioxide is produced as a by-product of this process. The produced hydrogen constitutes clean hydrogen using CCS if the produced carbon dioxide is captured and permanently sequestered. We are still assessing the impact of these revisions on the eligibility of certain of our hydrogen and CCS projects for LCFS credits; however, to the extent CARB disfavors clean hydrogen using CCS projects from generating credits under the LCFS, our low carbon projects may not be able to capture their full value as originally estimated. This could result in certain projects becoming less or non-economic, which in turn could limit our ability to successfully pursue hydrogen and CCS projects in the future.

California's cap-and-trade program is a market-based emissions reduction program to limit GHG emissions. The program applies to major GHG-emitting sources such as electricity generation and industrial facilities, with set carbon benchmarks that gradually decrease each year. Covered emitters must either reduce their emissions below this benchmark or purchase allowances at auction, incentivizing investment in lower-emissions technologies. However, unlike the LCFS, CARB's CCS protocol has not yet been incorporated into the cap-and-trade program. The timing for the adoption of a protocol is unclear and it may not happen at all. Until CARB adopts a CCS protocol for cap-and-trade, the program considers GHG emissions sequestered using CCS to be no different than unabated emissions. If CARB fails to adopt a CCS protocol for cap-and-trade, this could result in certain projects becoming less or non-economical, which in turn could limit our ability to successfully pursue certain CCS projects in the future. We are exploring alternative approaches to account for carbon capture under the California cap-and-trade program, but we cannot guarantee that CARB will accept these alternative approaches or that we will be able to pursue them in a timely manner to support our carbon capture projects.

In addition, the current and former Governors of California and certain municipalities in California have announced their commitment to adhere to GHG reductions called for in the Paris Agreement through executive orders, pledges, resolutions and memoranda of understanding or other agreements with various other countries, U.S. states, Canadian provinces and municipalities. In furtherance of this commitment, in September 2022, the Governor of California signed Assembly Bill No. 1279 into law, which codifies a previously issued executive order by the Governor's Office requiring the state to achieve carbon neutrality by 2045. In addition, the Governor of California previously issued an executive order directing several agencies to take further actions with respect to reducing emissions of GHGs. The Governor has also directed state agencies to implement other measures to mitigate climate change and strengthen biodiversity, such as via the conservation of 30% of state lands and waters by 2030. For more information, see *Part I, Item 1A – Risk Factors, Risks Related to Regulation and Government Action, Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material adverse effect on our business, and financial condition and results of operations.*

The EPA and the CARB have also expanded direct regulation of methane as a contributor to GHG emissions. In response to President Biden's executive order calling on the EPA to revisit federal regulations regarding methane, in December 2023, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources, known as OOOOc. Under the final rules, states have two years to prepare and submit their plans to impose methane emissions controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. The rules have been subject to legal challenge, and may also be repealed or modified by the current administration, though we cannot predict the substance or timing of such changes, if any.

Relatedly, beginning in 2025, certain oil and gas facilities, including those we own and operate, must pay a fee to EPA pursuant to the Inflation Reduction Act, starting at $900 per metric ton of methane emitted in 2024 and annually thereafter, with the fee rising to $1,200 in 2025 and $1,500 in 2026 and thereafter. However, compliance with the EPA's methane rules, discussed above, would exempt an otherwise covered facility from the requirement to pay the fee. At this time, it remains uncertain whether the current administration will take any action to revise or repeal the methane charge rule or if Congress may take action to repeal or revise the IRA, including with respect to the methane charge rule.

Regulation of Transportation, Marketing and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the U.S. are set by the market and are not presently regulated. In 2015, the U.S. federal government lifted restrictions on the export of domestically produced oil that allows for the sale of U.S. oil production, including ours, in additional markets.

Federal and state laws regulate transportation rates for, and marketing and sale of, petroleum products and electricity with respect to certain of our operations and those of certain of our customers, suppliers and counterparties. Such regulations also govern:

- interstate and intrastate pipeline transportation rates for oil, natural gas and NGLs in regulated pipeline systems;
- prevention of market manipulation in the oil, natural gas, NGL and power markets;
- market transparency rules with respect to natural gas and power markets;
- the physical and futures energy commodities market, including financial derivative and hedging activity; and
- prevention of discrimination in natural gas gathering operations in favor of producers or sources of supply.

The federal and state agencies overseeing these regulations have substantial rate-setting and enforcement authority, and violation of the foregoing regulations could expose us to litigation with government authorities, counterparties, special interest groups and others.

International treaties and regulations also affect the marketing or sale of our products. For example, on January 1, 2020, the International Maritime Organization reduced the maximum sulfur content in marine fuels from 3.5% to 0.5% by weight under the International Convention for the Prevention of Pollution from Ships. Under this IMO 2020 rule, ships must either switch to low-sulfur fuels or install scrubbing facilities for emission controls, which may affect the price of and demand for varying grades of crude oil, both internationally and in California.

In addition, mandates or subsidies have been adopted or proposed by the state and certain local governments to require or promote renewable energy or electrification of transportation, appliances and equipment, or prohibit or restrict the use of petroleum products, by our customers or the public. For example, in January 2020, the California Public Utilities Commission (CPUC) commenced a rulemaking to develop a long-term natural gas planning strategy to ensure safe and reliable gas systems at just and reasonable rates during what it describes as a 25-year transition from natural gas-fueled technologies to meet the state’s GHG goals. In addition, several municipalities in California enacted ordinances in 2019 that restrict the installation of natural gas appliances and infrastructure in new residential or commercial construction, which could affect the retail natural gas market of our utility customers and the demand and prices we receive for the natural gas we produce. Several of these ordinances face legal challenges.

Available Information

We make available, free of charge on our website www.crc.com, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, Definitive Proxy Statements and amendments to those reports filed or furnished, if any, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Unless otherwise provided herein, information contained on our website is not part of this report. The SEC maintains an internet site, http://www.sec.gov, that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

ITEM 1A RISK FACTORS

Described below are certain risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flow. These risks are not the only risks we face. Our business could also be affected materially and adversely by other risks and uncertainties that are not currently known to us or that we currently deem to be insignificant.

Summary:

Risks Related to Our Oil and Gas Business

- Prices for our products are volatile and a substantial decline in prices over an extended period could have a material adverse effect on our financial condition, results of operations, cash flow and ability to invest in our assets.
- Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area, including drought, earthquake and wildfire risks.
- Drilling for and producing oil and natural gas carries significant operational risks and uncertainty. We may not drill wells at the times we schedule, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.
- Our business involves substantial capital investments, and we may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production.
- We may be negatively impacted by inflation.
- We are subject to economic downturns and the effects of public health events which may materially and adversely affect the demand and the market price for our products.
- The military conflicts in Ukraine, Israel and other countries in the Middle East have caused price volatility and geopolitical instability which impact our business.
- Some of our competitors have greater resources than us and we may not be able to successfully compete in acquiring and developing new properties.
- Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.
- Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be higher or lower than estimated.
- From time to time we may engage in step-out drilling, or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.

Risks Related to Carbon TerraVault and Our Carbon Management Segment

- We may not be able to grow our Carbon TerraVault business and develop large scale CCS projects.
- Our ability to achieve our emissions goals and other goals related to carbon management activities is subject to risks and uncertainties.
- Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may not currently be sufficient for our Carbon TerraVault business and other CCS projects to be economical, may not be fully realized, or could be changed or terminated.
- Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties which could adversely affect our ability to implement our carbon management strategy.

Risk Factors Related to Our Business Generally

- Increasing activism against the industries in which we operate, including the oil and gas industry and our involvement in carbon capture, storage, utilization and sequestration, presents risks to our business.

- Increased attention to ESG matters may adversely impact our business.
- Acquisition and disposition activities, including continued integration of the Aera Merger, involve substantial risks.
- We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- Cybersecurity attacks, systems failures and other disruptions could adversely affect us.

Risks Related to Regulation and Government Action

- We may face material delays related to our ability to timely obtain permits necessary for our operations, or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.
- We may face increased local restrictions on oil and gas exploration and production operations or even be prohibited from operating in certain areas as a result of recently enacted California legislation.
- Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, results of operations and financial condition.
- Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.
- Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation much of which is still being developed. Failure to comply with these regulations and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, results of operations and financial condition.
- New and developing regulations related to CO_2 unitization, permitting and pipeline safety could negatively impact our business, financial condition and results of operations.
- Our operations and financial performance may be negatively affected directly or indirectly by changes in trade policies and tariffs.
- Concerns about climate change and other environmental issues may prompt governmental action that could have a material adverse effect on our operations or results.
- The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.
- Tax law changes could have an adverse effect on our financial condition, results of operations and cash flows.
- Financial assurance requirements related to plugging and abandonment costs, decommissioning, and site restoration on those who acquire the right to operate wells and production facilities could impact our ability to sell or acquire assets in California or increase our costs in connection with the same.

Risks Related to our Indebtedness

- We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.
- Our existing and future indebtedness may adversely affect our business and limit our financial flexibility.
- We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.

- The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our ability to use or access capital.
- Restrictive covenants in our Revolving Credit Facility and the indentures governing our Senior Notes may limit our financial and operating flexibility.
- Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Risks Related to Our Common Stock

- Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.
- The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.
- Future issuances of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.
- The ownership position of certain of our stockholders limits other stockholders' ability to influence corporate matters and could affect the price of our common stock.
- Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

Risks Related to Our Oil and Gas Business

Prices for our products are volatile and a substantial decline in prices over an extended period could have a material adverse effect on our financial condition, results of operations, cash flow and ability to invest in our assets.

Our financial condition, results of operations, cash flow and ability to invest in our assets are highly dependent on oil, natural gas and NGL prices. A substantial decline in prices for these products would reduce our cash flows from operations and could reduce our borrowing capacity or cause a default under our financing agreements.

Prices for oil, natural gas and NGL may fluctuate widely in response to relatively minor changes in domestic and global supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and global inventory levels;
- political and economic conditions, including international disputes such as the conflicts in Ukraine, Israel and other countries in the Middle East;
- pandemics, epidemics, outbreaks or other public health events, such as the COVID-19 pandemic;
- the actions of OPEC and other significant producers and governments;
- changes or disruptions in actual or anticipated production, refining and processing;
- worldwide drilling and exploration activities;
- government energy policies and regulation, including with respect to climate change;
- the effects of conservation;
- natural disasters, weather conditions and other seasonal impacts;
- speculative trading in derivative contracts;
- currency exchange rates;
- technological advances;
- transportation and storage capacity, bottlenecks and costs in producing areas;
- the price, availability and acceptance of alternative energy sources;
- regional market conditions; and
- other matters affecting the supply and demand dynamics for these products.

Lower prices could have adverse effects on our business, financial condition and results of operations, including:

- reducing our proved oil and natural gas reserves over time;
- limiting our capital expenditures and our ability to grow or maintain future production;
- causing a reduction in our borrowing base under our Revolving Credit Facility, which could affect our liquidity;
- reducing our cash flow and ability to make interest payments or maintain compliance with financial covenants in the agreements governing our indebtedness, which could trigger mandatory loan repayments and default and foreclosure by our lenders and bondholders against our assets; and
- limiting our access to funds through the capital markets and the price we could obtain for asset sales or other monetization transactions.

Our hedging program does not provide downside protection for all of our production. As a result, our hedges do not fully protect us from commodity price declines, and we may be unable to enter into acceptable additional hedges in the future.

Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area, including drought, earthquake and wildfire risks.

Our operations are concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. Changes in state or regional laws and regulations affecting our operations, local price fluctuations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. Our operations are also exposed to natural disasters and related events common to California, such as wildfires, mudslides, high winds, earthquakes and extreme weather events, and the potential increase to the frequency of drought and flooding. Further, our operations may be exposed to power outages, mechanical failures, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, prevent development of lease inventory before expiration and limit access to markets for our products.

Drilling for and producing oil and natural gas carries significant operational risks and uncertainty. We may not drill wells at the times we schedule, or at all. Wells we do drill may not yield production in economic quantities or generate the expected payback.

The development of oil and natural gas properties are subject to numerous operational risks, including the risks of permitting or construction delays, equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts), cost over-runs and other associated risks.

Development activities also depend in part on our analysis of geophysical, geologic, engineering, production and other technical data and processes, including the interpretation of 3D seismic data. This analysis is often inconclusive or subject to varying interpretations.

Any of the forgoing operational risks could cause actual results to differ materially from the expected payback or cause a well or project to become uneconomic or less profitable than forecast.

We have specifically identified drilling activities for the next several years, which are an integral part of our production strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling activities do not generate sufficient production and reserves, we may be forced to curtail drilling or development of these and other projects. We make assumptions about the consistency and accuracy of data when we identify locations for new wells or opportunities for workovers, sidetracks and deepenings, and these assumptions may prove inaccurate. We cannot guarantee that our identified new well drilling locations will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations or from our other drilling activities. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented 2% of our total net undeveloped acreage at December 31, 2024.

Our business involves substantial capital investments and we may be unable to fund these investments which could lead to a decline in our oil and natural gas reserves or production.

Our development activities involve substantial capital investments. We intend to fund our 2025 capital program using cash flow from operations. Accordingly, a reduction in projected operating cash flow could cause us to reduce our future capital investments. In general, the ability to execute our capital plan depends on a number of factors, including:

- the amount of oil, natural gas and NGLs we are able to produce;
- commodity prices;
- regulatory and third-party approvals;
- our ability to timely drill, complete and stimulate wells;
- our ability to secure equipment, services and personnel; and
- our liquidity and ability fund capital expenditures.

Access to future capital may be limited by our lenders, capital markets constraints, activist funds or investors, or poor stock price performance. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production levels and development activities and limit our ability to make acquisitions or enter into partnerships and farmout arrangements.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent we have insufficient cash flow from operations or liquidity to fund those activities. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

We may be negatively impacted by inflation.

Increases in inflation may have an adverse effect on us. Operating and capital costs in the oil and natural gas industry are heavily influenced by commodity prices, including the prices we pay for electricity, natural gas and steel-based materials. For example, we use natural gas in our operations to generate steam for use in steamfloods and we purchase additional volumes of natural gas to support our operations. We also use electricity generated by our Elk Hills power plant to power our oil and gas operations in the Elk Hills field. If we are unable to generate sufficient electricity for use in our operations, we may need to purchase electricity from third parties. Increases in the volumes or prices of commodities used in our operations could cause increases in our operating expenses. We attempt to manage our exposure to price increases of certain commodities used in our operations, including natural gas, by entering into hedges or longer-term contracts with fixed price arrangements. However, these measures do not fully protect us from the effects of commodity price increases and we may not be able to enter into similar arrangements in the future on acceptable terms or at all. Inflation could also result in higher interest rates in the United States, which could increase the cost of future financing efforts.

We are subject to economic downturns and the effects of public health events which may materially and adversely affect the demand and the market price for our products.

The marketing of our oil, natural gas and NGLs is dependent upon the existence of adequate markets for our products. Imbalances between the supply of and demand for these products, including as a result of economic downturns or the effects of public health events, could cause extreme market volatility and a substantial adverse effect on commodity prices. A world health event, the extent of actions that may be taken to contain or treat its impact, and the impacts on the economy generally and oil prices in particular, are uncertain, rapidly changing and hard to predict. This uncertainty could force us to reduce costs, including by decreasing operating expenses and lowering capital expenditures, and such actions could negatively affect future production and our reserves. We may experience labor shortages if our employees are unwilling or unable to come to work because of illness, quarantines, government actions or other restrictions in connection with a pandemic. If our suppliers cannot deliver the materials, supplies and services we need, we may need to suspend operations. In addition, we are exposed to changes in commodity prices which have been and will likely remain volatile. We cannot predict the duration and extent of a pandemic's adverse impact on our operating results.

Additionally, to the extent a world health event adversely impacts the global business and economic environment, which adversely affects our business and financial results, it may also have the effect of heightening or exacerbating many of the other risks described in the *Risk Factors* herein.

The military conflicts in Ukraine, Israel and other countries in the Middle East have caused price volatility and geopolitical instability which impact our business.

The military conflicts in Ukraine, Israel and other countries in the Middle East have caused volatility in the prices of natural gas, oil and NGLs, and the extent and duration of the military action, sanctions and resulting market disruptions have been significant and could continue to have a substantial impact on the global economy and our business for an unknown period of time.

In the fourth quarter of 2024, OPEC+ extended its nearly 4 million barrels per day voluntary reduction in production quotas as well as 2.2 million barrels per day in voluntary production curtailments. While actual OPEC+ production capabilities are difficult to discern, any return to previous targeted production levels—coupled with expanding Iranian, Venezuelan, Brazilian and U.S. production—could cause commodity prices to decline which would reduce the revenues we receive for our oil production.

Materialization of either of the events described above may also magnify the impact of the other risks described in this "*Risk Factors*" section.

Some of our competitors have greater resources than us and we may not be able to successfully compete in acquiring and developing new properties.

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods and services and hiring and retaining employees needed to operate and manage our business and marketing natural gas, NGLs or oil. Competitors include a multinational oil company, independent production companies and individual producers and operators. In California, our competitors are few, which may limit available acquisition opportunities. Some of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address such competitive factors more effectively than we can or withstand industry downturns more easily than we can.

Our hedging activities limit our ability to realize the full benefits of increases in commodity prices.

We enter into hedges to mitigate our economic exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. Our Revolving Credit Facility also includes a covenant that would require us to enter into hedges if the ratio of our indebtedness to Consolidated EBITDAX (as defined in the Revolving Credit Facility) exceeds certain levels. These hedges expose us to the risk of financial losses depending on commodity price movements and may prevent us from realizing the full benefits of price increases. Our ability to realize the benefits of our hedges also depends in part upon the counterparties to these contracts honoring their financial obligations. If any of our counterparties are unable to perform their obligations in the future, we could be exposed to increased cash flow volatility that could affect our liquidity. In addition, our level of hedging activity may be impacted by financial regulations that could increase our costs of hedging and/or limit the number of hedging counterparties available to us.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be higher or lower than estimated.

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions that require significant judgment in the evaluation of available information. Our assumptions may ultimately prove to be inaccurate. Additionally, reservoir data may change over time as more information becomes available from development and appraisal activities.

Our ability to maintain or increase our reserves, other than through acquisitions, depends on our ability to drill new wells, which is currently limited due to the lack of availability of new well permits as described below. See *Risks Related to Regulation and Government Action – We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.*

To the extent we are able to drill new wells, our ability to maintain or increase reserves (other than through acquisitions) is contingent on the success of improved recovery, extension and discovery projects, each of which hinges on reservoir characteristics, technology improvements and oil and natural gas prices, as well as capital and operating costs. Many of these factors are outside management's control and will affect whether the historical sources of proved reserves additions continue to provide reserves at similar levels.

Generally, lower prices adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the applicable rules or may be removed due to the lack of drilling permits or insufficient capital to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although 85% of our estimated proved reserve volumes as of December 31, 2024, were audited by our independent petroleum engineer, NSAI, we cannot guarantee that the estimates are accurate.

Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions. Changes in these variables and assumptions could require us to make significant negative reserves revisions, which could affect our liquidity by reducing the borrowing base under our Revolving Credit Facility. In addition, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions.

From time to time we may engage in step-out drilling or drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.

The risk profile for step-out drilling or drilling in new or emerging plays is higher than for other locations because we have less geologic and production data and drilling history, in particular for drilling in unconventional reservoirs, which are in unproven geologic plays. Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, capital availability, costs, drilling results, regulatory approvals, available transportation capacity and other factors. We may not find commercial amounts of oil or natural gas or the costs of drilling, completing, stimulating and operating wells in these locations may be higher than initially expected. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. In either case, the value of our undeveloped acreage may decline and could be impaired.

Risks Related to Carbon TerraVault and Our Carbon Management Segment

We may not be able to grow our Carbon TerraVault business and develop large scale CCS projects.

We are developing a carbon management business in California that relies on CCS projects. To our knowledge, there are no existing large-scale CCS projects in California similar to those that we are seeking to develop. These projects face operational, technological and regulatory risks that could be considerable due to the early-stage nature of these projects and the sector generally. Our ability to successfully develop these projects depends on a number of factors that we are not able to fully control, including the following:

- Obtaining Class VI permits for carbon dioxide injection and storage from the EPA may take years, and the time to obtain permits may vary with the complexity and type of storage reservoir. The analysis of the suitability of a reservoir for carbon sequestration is complex and our permit applications are subject to extensive review by the EPA. There can be no assurances that the EPA will release Class VI permits to us when we expect, if at all. Even if we are successful in our efforts to obtain Class VI permits, the permits could be subject to legal challenges.
- The development of large-scale CCS projects is an emerging sector and there are no meaningful precedents to gauge the likely range of economic terms upon which these projects may be feasibly developed. In addition, any of the operational, regulatory or financial risks described herein could cause actual results to differ materially from expected payback or cause a project to become uneconomic or less profitable than forecast.
- The development of CCS and related projects will likely require us, our joint venture partner, and third-party emitters to make significant capital investments in the relevant technology and infrastructure and we may not have sufficient capital resources to fund such investments. Such projects may also depend on third party financing and such financing may not be available on reasonable terms or at all. In some cases, these projects will involve the production and sale of hydrogen, ammonia or other products and markets for some of these products are still emerging.
- The development of a CCS project will likely require us to enter into long term binding agreements with large carbon emitters and other third parties and we may not be able to do so on agreeable terms or at all. Such agreements are complex and may involve allocation of not only fees but also various credits, incentives and environmental attributes associated with the

storage of CO_2. Not all emission sources produce sufficiently large quantities of pure or relatively pure streams of CO_2, or have installed equipment to capture such CO_2, so as to be useable in one or more of our CCS projects. As a result, we cannot assure whether we will be able to access CO_2 emissions in sufficient quantities or on terms that are acceptable to us.

- The development and operation of cost-effective, commercial-scale hydrogen and ammonia production facilities and associated sequestration facilities are highly complex. We may participate in the development of production facilities that provide the emissions for our CCS business. There can be no assurances that we or our partners will be able to successfully develop these production facilities, or that we will be able to develop the related sequestration facilities, in a timely manner or at all. In addition, there can be no assurances that these facilities can be maintained and operated over the longer term. The financing and development of these projects may depend on the availability of long term off-take agreements for these products and the market for hydrogen is still developing. It may not be possible for us or our partners to enter into these types of agreements on acceptable terms or at all.
- Certain of our anticipated CCS project sites rely on pore space that we do not own and we may need to enter into agreements with landowners to allow us to inject CO_2. The market for such landowner agreements is evolving with the evolution of the CCS industry and it may not be possible for us to enter into these types of agreements on acceptable terms or at all.
- Complex recordkeeping and GHG emissions/sequestration accounting may be required in connection with one or more of our projects, which may increase the costs of such operations. Different methodologies may be required for various regulatory and non-regulatory accounts regarding GHG emissions/sequestration at one or more of our projects, including but not limited to compliance with the EPA's Mandatory Greenhouse Gas Reporting Program.
- Carbon capture may be viewed as a pathway to the continued use of fossil fuels and there may be organized opposition (including lawsuits) to CCS projects from environmental groups, local residents and legislators.
- Other regulatory uncertainties described below.

There can be no assurances that we will successfully develop our CCS projects, including our cryogenic gas plant CCS project or CalCapture, and a failure to do so would have an adverse effect on our carbon management business and its prospects. Our carbon management segment is currently in an early stage of development, and we do not expect the failure of a single CCS project to create an impact on our overall financial condition or operations. However, as the scale of our CCS projects grows, so will its impact on our overall financial condition and operations. Moreover, our failure to successfully develop our CCS projects would adversely affect our ability to claim emissions reductions related to our sequestration activities and our ability to meet our carbon management goals, which in turn could have an adverse effect on our business and reputation.

Our ability to achieve our emissions and other goals related to our carbon management activities is subject to risks and uncertainties.

We have adopted a number of targets and objectives related to sustainability matters. Our efforts to research, establish, accomplish, and accurately report on these targets and objectives expose us to numerous operational, reputational, financial, legal, and other risks. Our ability to achieve any stated target or objective is not guaranteed and is subject to numerous factors and conditions, some of which are outside of our control. We are reviewing the impact of the Aera Merger and its assets on our ability to meet our previously announced 2045 Full-Scope Net Zero goal and may revise our goal to reflect our current business and other considerations. In any event, this goal includes Scope 1, 2 and 3 emissions and estimation and management of Scope 3 emissions are subject to some degree of uncertainty. We cannot guarantee that we have been able to completely quantify the full scope of our emissions and account for mitigating all such emissions in our Full-Scope Net Zero goal.

Our ability to achieve our emissions goal relies heavily on our ability to develop our Carbon TerraVault business and related CCS projects, which is subject to uncertainties and risks (including those risks described herein), such as the timely receipt of permits and third party challenges relating to the same. In addition, the commercial and regulatory environment related to emissions reductions and reporting is evolving and uncertain, and changes in GHG emission accounting methodologies or new developments related to climate science could impact our ability to claim emissions reductions related to our sequestration activities and timely achieve our emissions goal or at all. If we are not able to successfully develop Carbon TerraVault and its CCS projects and claim related emissions reductions, our ability to achieve our emissions goal would be materially and adversely affected.

Our business may face increased scrutiny from investors and other stakeholders related to our sustainability activities, including the goals, targets, and objectives that we announce, and our methodologies and timelines for pursuing them. If our sustainability practices do not meet investor or other stakeholder expectations and standards, which continue to evolve, our reputation, our ability to attract or retain employees, and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue or fulfill our sustainability-focused goals, targets, and objectives, to comply with ethical, environmental, or other standards, regulations, or expectations, or to satisfy various reporting standards with respect to these matters, within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation.

Our Carbon TerraVault business and other CCS projects depend on financial and tax incentives to be economical, and these incentives may not currently be sufficient for our Carbon TerraVault business and other CCS projects to be economical, may not be fully realized, or could be changed or terminated.

Congress has incentivized the development of carbon capture projects, clean hydrogen production projects and other projects relating to the production of certain clean fuels through the establishment of various tax credits, including the 45Q credit (credit for carbon oxide sequestration) and the 45V credit (credit for production of clean hydrogen). The successful development of our Carbon TerraVault business and other CCS projects is dependent upon our ability to directly or indirectly benefit from these tax credits. The amount of tax credits from which we may directly or indirectly benefit in connection with our Carbon TerraVault business and other CCS projects is dependent upon satisfaction of certain requirements, some of which have not been fully developed and issued by the Treasury Department and IRS, and we cannot assure you that we (or our partners) will be able to satisfy those requirements. For example, the Treasury Department and IRS recently issued final regulations pertaining to the 45V credit which, among other things, imposed certain requirements, restrictions and limitations on the use of renewable natural gas in connection with the production of clean hydrogen that qualifies for the 45V credit, which could have a negative impact on the development of future hydrogen projects in connection with our Carbon TerraVault business. Additional financial incentives may also be required for our Carbon TerraVault business and other CCS projects to be economical. In particular, we anticipate that CCS projects associated with carbon emission reductions for transportation fuels will generate LCFS credits and that these additional credits will improve the economics of CCS projects. If the existing legal requirements for incentives such as the 45Q credit, the 45V credit or LCFS credits are subsequently amended in a manner that such incentives no longer apply or are restricted in application, directly or indirectly, to our projects, we may not be able to successfully achieve an economic return from our Carbon TerraVault business and our other CCS projects or, alternatively, the construction or operation of applicable projects may be substantially delayed such that one or more projects is unprofitable or otherwise infeasible.

The current administration signed several Executive Orders reversing, revoking or rescinding many climate-related actions and has expressed a desire to make modifications to the Inflation Reduction Act. On January 20, 2025, the current administration issued an Executive Order which paused distribution of federal funds appropriated through the IRA or the Infrastructure Investment and Jobs Act. The pause was aimed at providing time to review the processes, policies and issuance of various grants, loans, contracts or financial disbursements of appropriated funds but did not modify the IRA statutory language with respect to federal income tax credits, such as 45Q or 45V credits (for more information, see *Tax law changes could have an adverse effect on our business, financial condition and results of operations*). However, on January 29, 2025, the White House Office of Management and Budget rescinded the freezing of federal grants and loans, although not its efforts to review the processes with respect to federal spending. At this time, the potential impact of these various actions remains uncertain. If the current administration or Congress repeals, modifies, or otherwise limits the grants, funding and tax incentives made available under the IRA, such actions could particularly harm our carbon management business and its prospects.

If the existing legal requirements for incentives such as the 45Q credit, the 45V credit or LCFS credits are eliminated or subsequently amended in a manner that such incentives no longer apply or are restricted in application, directly or indirectly, to our projects, we may not be able to successfully achieve an economic return from our Carbon TerraVault business and our other CCS projects or, alternatively, the construction or operation of applicable projects may be substantially delayed such that one or more projects is unprofitable or otherwise infeasible.

The ability to monetize the 45Q credit is not certain. Either the owner of the carbon capture equipment or the sequester must have the ability to use the 45Q credit itself, or the owner of the carbon capture equipment must utilize direct pay (which is generally limited to the first five years of the twelve-year credit period), procure tax equity financing, or transfer the credits to another taxpayer. Similar issues exist with respect to the monetization of the 45V credit. The accessibility of direct pay, tax equity financing, and the credit transfers market for tax credits provided under the Inflation Reduction Act is still developing for the 45Q and 45V credits, and therefore uncertainties and complexities with respect to our (or our partners) ability to efficiently monetize the 45Q credit and the 45V credit exist.

The 45Q credit and the LCFS credits require that the captured CO_2 be stored in secure geological storage for long periods of time. If we are not able to satisfy this requirement for the duration of time required, there is the risk of recapture of 45Q credits or LCFS credits from us (or our partners) by the government, as well as a risk of indemnification obligations to our partners, claims from landowners and potential for fines and penalties for violations of environmental requirements. Accidental releases of CO_2 could also adversely impact our ability to meet our emissions goals.

There can be no assurances that we (or our partners) will successfully comply with the requirements for the available tax credits or LCFS, and such failure could have an adverse effect on our business, financial condition and results of operations.

Our Carbon TerraVault JV with Brookfield is subject to inherent uncertainties which could adversely affect our ability to implement our carbon management strategy.

In August 2022, we entered into the Carbon TerraVault JV with Brookfield to pursue the development of a carbon management segment in California. The management and financing of the joint venture are subject to inherent uncertainties. These uncertainties could potentially force us to delay or cancel CCS projects or to seek alternative sources of capital to fund our CCS projects, any of which could adversely affect our ability to achieve our emissions and other goals related to our carbon management activities.

Brookfield has committed an initial $500 million to invest in CCS projects that are jointly approved through Carbon TerraVault JV. Brookfield has contributed $92 million to date. The remaining amount of Brookfield’s initial investment will depend on the amount of storage capacity that is permitted subject to certain contractual adjustments. The parties have certain put and call rights with respect to the 26R reservoir if certain milestones are not met. Future storage projects for Brookfield's initial commitment are subject to approval of the joint venture, including Brookfield. There can be no assurances that any of these funding milestones will be achieved so that Brookfield will fund the rest of its commitment.

Furthermore, even though we own a 51% interest in the Carbon TerraVault JV, we share decision making power with Brookfield on matters that most significantly impact the economic performance of the joint venture. Any failure to reach a decision with Brookfield could potentially prevent or delay our pursuit of CCS projects or cause such projects to be cancelled. Moreover, if Brookfield does not approve a proposed CCS project that we want to pursue, we will have to seek alternative sources of capital to fund the project and there can be no assurances that such sources of capital will be available.

Risk Factors Related to Our Business Generally

Increasing activism against the industries in which we operate, including the oil and gas industry and our involvement in carbon capture, storage, utilization and sequestration, presents risks to our business.

Opposition toward oil and gas drilling and development activity has been growing over time. Companies in the oil and gas industry are often the target of efforts to delay or prevent oil and gas development by non-governmental organizations and individuals. These activists use a variety of tactics that primarily rely on allegations regarding safety, environmental compliance and business practices. At both the state and federal level, these tactics include seeking changes to laws, pressuring governmental agencies to promulgate regulations or engage in rulemaking, or pursuing litigation. For example, we were recently a named real party in interest in *Center for Biological Diversity v. City of Long Beach, Long Beach City Council, California State Lands Commission, et al.*, a lawsuit brought by an environmental non-governmental organization that sought the shut down of the Long Beach Unit on the basis of a purported CEQA violation by certain governmental entities. While the court ruled against the claimants in this matter, we cannot provide any assurances that we will be similarly successful in any future litigation by activists.

This opposition also extends to our carbon management segment as certain activists oppose carbon capture and sequestration efforts by the oil and gas industry for various reasons. For example, on November 22, 2024, a group of non-governmental organizations filed a Petition for Writ of Mandate and Complaint for Injunctive Relief against Kern County and its Board of Supervisors (CTV I Complaint) in Kern County for our CTV I project. See *Regulation of Carbon Capture, Sequestration and Storage – CCS Project Permitting*. Such lawsuits have the potential to delay timely construction of the project and commencement of operations and could otherwise have a material and adverse effect on our carbon management business and its prospects.

Due to heightened concerns around climate change and GHG emissions, there is often considerable pressure on lawmakers, regulators and others to take action with respect to these allegations regardless of their perceived merit. This pressure is particularly high in California. We may need to incur significant costs associated with responding to these initiatives and such actions may have a material adverse effect on our financial results. Complying with any resulting additional legal or regulatory requirements that are substantial or prevent our activity could have a material adverse effect on our business, financial condition and results of operations.

Increased attention to ESG matters may adversely impact our business.

We face increased attention and expectations from various sources related to our business. This includes increased social expectations on energy companies to address climate change and other environmental and social impacts. In addition, investors and others have evolving expectations regarding voluntary or mandatory ESG disclosures. Finally, increased consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation. Any of the foregoing negative impacts on our stock price and access to capital. Increased attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors. While we may participate in various voluntary frameworks and certification programs to improve or support the ESG profile of our operations and products, we cannot guarantee that such participation or certification will have the intended results on our or our products' ESG profile.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures will be based on expectations and assumptions or hypothetical scenarios that may or may not be representative of actual risks or events, including the costs associated therewith. Such expectations, assumptions or hypothetical scenarios are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established approach to identifying, measuring, and reporting on many ESG matters. Additionally, while we may also announce various voluntary ESG targets, such targets are often aspirational and may be subject to change depending on changed circumstances, methodologies, business forecasts or other factors. For example, we are reviewing the impact of the Aera Merger and its assets on our ability to meet our previously announced 2045 Full-Scope Net Zero goal and may revise our goal to reflect our current business and other considerations. We may not be able to meet such targets in the manner or on such a timeline as initially contemplated, including, but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such results. To the extent we do meet such targets, they may ultimately be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that, notwithstanding our reliance on any reputable third-party registries, that the offsets we do purchase will successfully achieve the emissions reductions they represent. Some of these arrangements may receive scrutiny from certain constituencies who criticize the methodology of offsets or do not believe offsets should be utilized to neutralize GHG emissions. Also, despite these aspirational goals, we may receive pressure from investors, lenders, or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to pursue or implement such goals because of potential costs or technical or operational obstacles.

Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to evaluate their investment and voting decisions. Companies in the energy industry, and in particular those focused on oil or natural gas extraction, often do not score as well under ESG assessments compared to companies in other industries. While such ratings do not impact all investors' investment or voting decisions, unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of their investment away from the fossil fuel industry to other industries which could have a negative impact on our stock price and our access to and costs of capital. To the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations.

Public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain employment practices or social initiatives, are becoming increasingly subject to heightened scrutiny from public and governmental authorities. For example, the SEC has recently taken enforcement action against companies for ESG-related misconduct, including alleged “greenwashing,” *i.e.*, misleading information or false claims overstating potential ESG benefits. Certain non-governmental organizations and other private actors have filed lawsuits against entities under various securities and consumer protection laws alleging that certain ESG statements, goals, or standards were misleading, false or otherwise deceptive. Certain employment practices or social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. More recent political developments could mean that the Company faces increasing criticism or litigation risks from certain “anti-ESG” parties, including various government agencies. Such sentiment may focus on the Company’s environmental commitments (such as reducing GHG emissions) or its pursuit of certain employment practices or social initiatives, which anti-ESG proponents may assert as unlawful, political or polarizing in nature or are alleged to violate laws based, in part, on changing priorities of, or interpretations by, federal agencies or state governments. Consideration of ESG-related factors in the Company’s decision-making could be subject to increasing scrutiny and objection from such anti-ESG parties. As a result, the Company may be subject to pressure from the media or through other means, such as governmental investigations, enforcement actions, or other proceedings, all of which could adversely affect our reputation and our business. Accordingly, there may be increased costs related to review, implementation, and management of such policies, as well as compliance and litigation risks based both on positions we do or do not take, or work we do or do not perform.

Such ESG-related matters may also impact our customers or suppliers, which may adversely impact our business, financial condition, or results of operations.

Acquisition and disposition activities, including continued integration of the Aera Merger, involve substantial risks.

We engage in acquisition activities from time to time, including the Aera Merger which closed on July 1, 2024. The Aera Merger and other acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs or experience other integration difficulties;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing for recovering the reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and incomplete, and we may be unable to make these assessments with a high degree of accuracy.

Our acquisition activities may require us to seek approvals from our shareholders, government agencies or other regulatory bodies, depending on the nature and extent of the businesses being acquired. There can be no assurances that we would be able to obtain such approvals. If we are not able to complete acquisitions, we may not be able to grow our reserves or develop our properties in a timely manner or at all.

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Our disposition activities carry risks that we may:

- not be able to realize reasonable prices or rates of return for assets;
- be required to retain liabilities that are greater than desired or anticipated;
- experience increased operating costs; and
- reduce our cash flows if we cannot replace associated revenue.

There can be no assurance that we will be able to divest assets on financially attractive terms or at all. Our ability to sell assets is also limited by the agreements governing our indebtedness. If we are not able to sell assets as needed, we may not be able to generate proceeds to support our liquidity and capital investments.

In addition, we have expended and will continue to expend significant time and resources in connection with any future acquisition and disposition activities.

We may incur substantial losses and be subject to substantial liability claims as a result of pollution, environmental conditions or catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our business and assets are subject to risks from natural disasters and operating risks associated with oil and natural gas exploration and production activities. Pollution or environmental conditions with respect to our operations or on or from our properties, whether arising from our operations or those of our predecessors or third parties, could expose us to substantial costs and liabilities. Such events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. The cost and availability of insurance for natural disasters has increased in recent years. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Cybersecurity attacks, systems failures, and other disruptions could adversely affect us.

We rely on electronic systems and networks to communicate, control and manage our exploration, development and production activities. We also use these systems and networks to prepare our financial management and reporting information, to analyze and store data and to communicate internally and with third parties, including our service providers and customers. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

Cybersecurity attacks on businesses have escalated and become more sophisticated. If we or the third parties with whom we interact were to experience a successful attack, the potential consequences to our business, workforce and the communities in which we operate could be significant. We utilize various technologies, controls and procedures, as well as internal staff and external specialists to protect our systems and data, to identify and remediate vulnerabilities and to monitor and respond to threats. However, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. If a breach occurs, it may remain undetected for an extended period of time. If we or third parties with whom we interact were to experience a cybersecurity attack or a successful breach, the potential consequences could be significant, including loss of data, loss of business, damage to our reputation, potential financial or legal liability requiring us to incur significant costs, disruptions related to investigations and costs related to remediation.

Energy-related assets may be at a greater risk of strategic terrorist attacks or cybersecurity attacks than other targets. A cybersecurity attack on the digital technology that controls most oil and natural gas refining and distribution necessary to transport and market our products could impact critical distribution and storage assets or the environment, disrupt energy markets by delaying or preventing product delivery, or make it difficult or impossible to accurately account for production and settle transactions.

As cybersecurity threats continue to evolve in sophistication and magnitude, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any cybersecurity vulnerabilities. Further, state and federal cybersecurity and data privacy legislation could result in complex new requirements that increase our cost of doing business.

Risks Related to Regulation and Government Action

We may face material delays related to our ability to timely obtain permits necessary for our operations or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments.

We must obtain various governmental permits to conduct exploration and production activities, as well as other aspects of our operations. Obtaining the necessary governmental permits is often a complex and time-consuming process involving numerous federal, state and local agencies. The duration and success of each permitting effort is contingent upon many variables not within our control. In the context of obtaining permits or approvals, the Company will need to comply with known standards, existing laws (such as CEQA), and regulations that may entail greater or lesser costs and delays depending on the nature of the activity to be permitted and the interpretation of the laws and regulations implemented by the permitting authority.

In recent years, we have experienced significant delays with respect to obtaining new well, sidetrack, deepening and rework permits from CalGEM for our operations. A variety of factors outside of our control can lead to such delays. Recent changes in CalGEM management have contributed to permitting delays and uncertainty with respect to our ability to timely obtain permits for our operations. Following such change in management, during the second half of 2023 CalGEM focused on the development of standard operating procedures (SOPs) for permit review, and as a practical matter ceased issuing permits pending the completion of this process. CalGEM released its SOP for the review of applications for rework permits in late Q4 2023 and recently finalized its Lead Agency Preliminary Review process for sidetrack permits. In 2024, CalGEM resumed issuing permits for reworks and sidetracks to CRC and other operators. Subject to limited exceptions, CalGEM has not issued any permits for new production wells to any operators since December 2022.

We have experienced delays obtaining permits as a result of litigation related to the Kern County EIR for the past several years. Most recently, in March 2023, Kern County was directed to prepare a revised EIR that corrects certain CEQA violations, circulate the revised EIR for public review and comment, and prepare and publish responses to any comments received before certifying the revised EIR. The suspension of the Kern County EIR remains in effect. We are in the process of pursuing alternative pathways for addressing CEQA compliance for our oil and natural gas permitting process, this would be a lengthy process and we cannot predict with complete certainty whether we would be able to timely obtain permits using this alternative.

As a result of these issues and current lack of permits with respect to our Kern County properties, we currently plan to operate one active rig within Kern County in 2025 and have the requisite number of permits in hand to keep that rig active throughout the year. We also plan to increase our active rig count in Kern County from one rig to two in the second half of 2025 based on our existing permits. However, there is no certainty that we will obtain permits on that timeline or at all, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations. In 2025, approximately $21 million of capital to develop proved reserves relates to drilling and completing sidetracks in Kern County for which we do not presently have a permit.

We have also experienced delays obtaining drilling permits from CalGEM since the passage of Senate Bill No. 1137, which established 3,200 feet as the minimum distance between new oil and natural gas production wells and certain sensitive receptors such as homes, schools and businesses open to the public. The law became effective January 1, 2023 and CalGEM issued emergency regulations implementing the requirements of the law on January 6, 2023. However, on February 3, 2023, the Secretary of State of California certified voter signatures collected in connection with a referendum for the November 2024 ballot to repeal Senate Bill No. 1137. However, in June 2024, the ballot proposal was withdrawn with the proposal's sponsors indicating a view to challenging Senate Bill No. 1137 in court. The provisions of Senate Bill No. 1137 became effective immediately in June 2024. Then, on September 30, 2024, the Governor signed into law Assembly Bill 218, which delays the deadline for some compliance with CalGEM's regulations implementing Senate Bill No. 1137 until July 1, 2026, and further delays compliance with certain other requirements of Senate Bill No. 1137 by up to three years. There is continued uncertainty with respect to the ability to book proved undeveloped reserves and drill within the setback zone established by Senate Bill No. 1137. As a result, we do not have and proved undeveloped reserves booked within currently defined setback zones as of year-end 2024. As a result of Senate Bill No. 1137, in addition to write-downs recorded in 2023, we further reduced the net present value of our proved undeveloped reserves by 6% and our overall proved reserves by 1% in 2024. We expect any further impact from SB 1137 to proved reserves to be minimal. (*See Part I, Item 1 and 2 – Business and Properties, Regulation of Exploration and Production Activities* for more information).

In 2025, none of our aggregate capital to develop proved reserves relates to drilling and completing wells in Wilmington for which we do not presently have a permit. We do not plan on operating an active drilling rig in Wilmington in 2025. However, there is no certainty that we will be able to obtain a permit in the future, which may further adversely affect our future development plans, proved undeveloped reserves, business, operations, cash flows, financial position and results of operations.

We cannot guarantee that these issues or new ones that may arise in the future will not continue to delay or otherwise impair our ability to obtain drilling permits. In the past we have generally been able to mitigate permitting risks by building up a reserve of drilling permits for use throughout the year, but as a result of the issues described above, we have not been able to build our reserve of approved permits to the same level as we have in the past. If we cannot obtain new drilling or sidetrack permits in a timely manner, we have limited options to meet our drilling plans, such as the use of workovers to extend the life of existing production, which may not ultimately be sufficient to achieve our business goals. Any continuing failure to obtain certain permits or the adoption of more stringent permitting requirements could have a material adverse effect on our business, financial condition and results of operations.

We may face increased local restrictions on oil and gas exploration and production operations or even be prohibited from operating in certain areas as a result of recently enacted California legislation.

On September 25, 2024, Assembly Bill 3233 (AB 3233) was enacted which authorizes local governments to prohibit, oil and gas operations or development, or impose regulations, limits or prohibitions that are more protective of public health, the climate or the environment than prescribed by state law, regulation or order on such oil and gas operations or development, within their jurisdiction, including with respect to existing operations. Prior to the passage of this law, certain local governments within California had previously taken steps to limit oil and gas operations that were struck down by California courts. Monterey County previously sought to ban only new production and prohibit the use of wastewater injection as a production method. The City and County of Los Angeles previously sought to both ban new wells and phaseout existing wells over a certain period of time. If these bans were enacted, for the year ended December 31, 2024, less than 1% of our net production and proved reserves were located in the City of Los Angeles; and our operations are otherwise in unincorporated areas of Los Angeles, which would not be affected by such bans. Approximately 2% of our net production and 1% of proved reserves were located in Monterey County as of and for the year ended December 31, 2024. Although both of those local measures were struck down in court, following the adoption of AB 3233, certain legal arguments used to challenge these local actions are no longer valid and it is possible that these or other local governments in places where we operate may pass similar regulations. It is difficult to predict how local governments in California may choose to exercise their new authority under AB 3233.

While there may be future legal challenges to AB 3233 and any local ordinances enacted thereunder, we cannot predict whether or not such challenges will be successful. Notwithstanding any potential claims for regulatory takings we may have in the event local jurisdictions seek to prohibit any of our existing operations, to the extent that the local governments in the areas where we operate in California enact new restrictions or prohibitions with respect to oil and gas exploration and production activities, we could face increased operating costs, loss of revenues, and other material and adverse impacts to our business and results of operations.

Recent and future actions by the State of California could reduce both the demand for and supply of oil and natural gas within the state and consequently have a material and adverse effect on our business, and financial condition and results of operations.

In recent years, the Governor of California, the Legislature and state agencies have taken a series of actions that could materially and adversely affect the state's oil and natural gas sector. For additional information, see *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities,* and *Risk Factors, We may face material delays related to our ability to timely obtain permits necessary for our operations, or be unable to secure such permits on favorable terms or at all as a result of numerous California political, regulatory, and legal developments*.

The trend in California is to impose increasingly stringent restrictions on oil and natural gas activities. We cannot predict what actions the Governor of California, the Legislature or state agencies may take in the future, but we could face increased compliance costs, delays in obtaining the approvals necessary for our operations, exposure to increased liability, or other limitations as a result of future actions by these parties. Moreover, new developments resulting from the current and future actions of these parties could also have a material and adverse effect on our ability to operate, successfully execute drilling plans, or otherwise develop our reserves. Accordingly, recent and future actions by the Governor of California, the Legislature, and state agencies could have a material and adverse effect on our business, results of operations, and financial condition.

Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products.

To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, inspection, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, protection of habitat and threatened or endangered species, air emissions, disposal of solid and hazardous waste, fluid injection and disposal and water consumption, recycling and reuse. For example, our operations in the Wilmington Oil Field utilize injection wells to reinject produced water pursuant to waterflooding plans. These operations are subject to regulation by both the City of Long Beach and CalGEM. We are currently in discussions with the City of Long Beach and CalGEM with respect to what injection well pressure gradient complies with CalGEM's requirements for the protection of underground aquifers while at the same time mitigating subsidence risks. CalGEM's local office has preliminarily indicated that the injection well pressure gradient should be reduced from the gradient that has been used for several decades. As part of our ongoing discussions, we and the City of Long Beach have provided CalGEM with technical information regarding how the historical injection well pressure gradient complies with CalGEM's requirements and to inform them of the absence of risk of leakage and a plan to gradually lower the injection gradient over time in a manner that we believe would mitigate subsidence risks. If CalGEM were to ultimately disagree and determine to reduce the injection well pressure gradient other than in a gradual manner or at a gradient which we believe is unnecessary, and we were unable to reverse that decision on appeal or other legal challenge, we expect that any such reduction in injection well pressure gradient for our operations in the Wilmington Oil Field could result in a decrease in production and reserves from the field.

Failure to comply may result in the assessment of administrative, civil and/or criminal fines and penalties, liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations or our access to property, water, minerals or other necessary resources, and may otherwise delay or restrict our operations and cause us to incur substantial costs. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our Carbon TerraVault business and our CCS projects are subject to extensive government regulation much of which is still being developed. Failure to comply with these regulations and obtain the necessary permits, or the development of government regulations that are unfavorable to our CCS projects, could have an adverse effect on our business, financial condition and results of operations.

Successful development of CCS projects in the United States require that we comply with what we anticipate will be a stringent regulatory scheme requiring that we obtain certain permits applicable to subsurface injection of CO_2 for geologic sequestration. Moreover, as the operator of our CCS projects, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. There are no assurances that we will be successful in obtaining or maintaining permits or adequate levels of financial assurance for one or more of our CCS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition, or otherwise.

Separately, permitting CCS projects requires obtaining a number of other permits and approvals unrelated to subsurface injection from various U.S. federal and state agencies, such as for air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility. We cannot guarantee that we will be able to obtain or maintain all applicable permits for CCS activities on a timely basis or on favorable terms, if at all. Moreover, to the extent any of our CCS projects will require any supporting pipeline infrastructure, we could face additional costs and delays obtaining the necessary permits and rights of ways for such infrastructure, and increased risk of opposition to our projects, which may ultimately mean we are unable to successfully pursue certain CCS projects because of these risks.

As CCS and carbon management represent an emerging sector, laws and regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent additional legal or regulatory requirements are imposed, are amended, or more stringently enforced, we may incur additional costs in the pursuit of one or more of our carbon capture projects, which costs may be material or may render any one or more of our projects uneconomical.

New and developing regulations related to the CO_2 unitization, permitting and pipeline safety could negatively impact our business, financial condition and results of operations.

Senate Bill No. 905 contemplates the development of unitization, permitting and pipeline safety regulations over a multi-year period to facilitate the development of CCS projects in California, though the legislation does not provide for compulsory unitization. Senate Bill No. 905 also provides for a unified permitting process to simplify the permitting process for CCS projects, although this will be optional for project applicants. Additionally, the law contemplates the implementation of a new regulatory program incorporating standards that are not yet defined and that could affect the timing of future CCS projects in California. The California Air Resources Board has been tasked with developing this proposed framework. We believe our Carbon TerraVault projects will continue to be developed on a timeline consistent with our initial expectations. These initial projects are not reliant on the unitization or permitting regulations being developed. In addition, our Carbon TerraVault projects are expected to either use emitters that are directly sited above these storage facilities or rely on pipelines for transporting CO_2 Senate Bill No. 905 provides that pipelines may be used to transport carbon dioxide to or from a carbon dioxide capture, removal or sequestration project only upon conclusion of PHMSA's rulemaking strengthening safety requirements for carbon dioxide pipelines. Although PHMSA released a notice of proposed rulemaking to this effect in early January 2025, it has not yet been published in the Federal Register and its disposition is uncertain at this time. The terms of these final pipeline safety regulations may impair or prohibit projects that rely on the transportation of CO_2.

Senate Bill No. 905 also prohibits CCS projects that utilize and permanently sequester CO_2 in connection with EOR projects. Although we do not have any existing oil and natural gas production or proved reserves associated with EOR projects, this legislation required us to transition our CalCapture project to target CCS and may require us to make other adjustments to projects in the future.

Our operations and financial performance may be negatively affected directly or indirectly by changes in trade policies and tariffs.

In recent years, the United States increased tariffs for certain goods, which triggered other nations to also increase tariffs on certain of their goods. In recent weeks, the current administration has made many announcements regarding tariffs and the extent and duration of such tariffs remain uncertain. If maintained, the newly announced tariffs and the potential escalation of trade disputes could pose a risk to our business and also directly impact our operating expenses. For example, recently announced 25% tariffs on imported steel are likely to lead to increased material costs.

Concerns about climate change and other environmental issues may prompt governmental action that could have a material adverse effect on our operations or results.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions, and regulation of GHGs and other air quality issues, may have a material adverse effect on our business in many ways, including increasing the costs to provide our products and services and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues at the federal, state and local level may increase our capital and operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions. California's cap-and-trade program operates under a market system and the costs of such allowances per metric ton of GHG emissions are expected to increase in the future as the CARB tightens program requirements and annually increases the minimum state auction price of allowances and reduces the state's GHG emissions cap. As the foregoing requirements become more stringent, we may be unable to implement them in a cost-effective manner, or at all.

In August 2022, President Biden signed the Inflation Reduction Act into law. The Inflation Reduction Act includes a charge on methane emissions that exceed certain thresholds from sources required to report their GHG emissions to the EPA, including certain oil and natural gas operations. The methane emissions charge began in 2024 at $900 per ton of methane, increased to $1,200 in 2025, and will be set at $1,500 for 2026 and subsequent years. We cannot predict if Congress may take actions to repeal or revise the Inflation Reduction Act, including with respect to the methane emissions charge. In fact, the full impact of future climate regulations is uncertain at this time and it is unclear what additional actions may be taken that may have an adverse effect upon our carbon management business and its prospects.

To the extent financial markets view climate change and GHG or other emissions as an increasing financial risk, this could adversely impact our cost of, and access to, capital and the value of our stock and our assets. Current investors in oil and natural gas companies may elect in the future to shift some or all of their investments into other sectors, and institutional lenders may elect not to provide funding for oil and natural gas companies. There is also 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, although this trend has waned recently and several high-profile banks and institutional investors have withdrawn from various associations that aim to limit financing of industries that emit significant GHG emissions. Additionally, in March 2024, the Securities and Exchange Commission (SEC) released a final rule that establishes a framework for the reporting of climate risks, targets and metrics. However, the future of the rule is uncertain at this time given that its implementation has been stayed pending the outcome of legal challenges. Moreover, the Commission may, under the current Administration seek to change or revoke the rule, though we cannot predict whether such action will occur or its timing. Relatedly, California has enacted new laws requiring additional disclosure with respect to certain climate-related risks and GHG emissions reduction claims. (See *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Climate Change and Greenhouse Gas (GHG) Emissions* for more information). Non-compliance with these new laws may result in the imposition of substantial fines or penalties. Other states are considering similar laws. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate-related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, additional costs to comply with any such disclosure requirements and increased costs of and restrictions on access to capital.

We believe, but cannot guarantee, that our local production of oil, NGLs and natural gas will remain essential to meeting California's energy and feedstock needs for the foreseeable future. We have also established 2030 Sustainability Goals for water recycling, renewables integration, methane emission reduction and carbon capture and sequestration in our life-of-field planning in an attempt to align with the state's long-term goals and support our ability to continue to efficiently implement federal, state and local laws, regulations and policies, including those relating to air quality and climate, in the future. However, there can be no assurances that we will be able to design, permit, fund and implement such projects in a timely and cost-effective manner or at all, or that we, our customers or end users of our products will be able to satisfy long-term environmental, air quality or climate goals if those are applied as enforceable mandates.

The adoption and implementation of new or more stringent international, federal, state or local legislation, regulations or policies that impose more stringent standards for GHG or other emissions from our operations or otherwise restrict the areas in which we may produce oil, natural gas, NGLs or electricity or generate GHG or other emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for or the value of our products and services. Additionally, political, litigation and financial risks may result in restricting or canceling oil and natural gas production activities, incurring liability for infrastructure damages or other losses as a result of climate change, or impairing our ability to continue to operate in an economic manner. Moreover, climate change may pose increasing risks of physical impacts to our operations and those of our suppliers, transporters and customers through damage to infrastructure and resources resulting from drought, wildfires, sea level changes, flooding and other natural disasters and other physical disruptions. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

The Inflation Reduction Act could accelerate the transition to a low-carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the Inflation Reduction Act into law. The Inflation Reduction Act contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and CCS, amongst other provisions. In addition, the Inflation Reduction Act imposes the first ever federal fee on the emission of GHGs through a methane emissions charge. The Inflation Reduction Act amends the Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge began in calendar year 2024 at $900 per ton of methane, increased to $1,200 in 2025, and will be set at $1,500 for 2026 and each year thereafter. Calculation of the fee is based on certain thresholds established in the Inflation Reduction Act. However, compliance with the EPA's new methane rules (see *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Climate Change and Greenhouse Gas (GHG) Emissions*) would exempt an otherwise covered facility from the requirement to pay the fee. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from fossil fuels towards lower- or zero-carbon emission alternatives. The methane charges and various incentives for clean energy industries could decrease demand for crude oil and natural gas and increase our compliance and operating costs, which consequently could have a material adverse effect on our business and results of operations. However, at this time, we cannot predict if Congress may take actions to repeal or revise the Inflation Reduction Act, including with respect to the methane emissions charge.

Tax law changes could have an adverse effect on our business, financial condition and results of operations.

We are subject to taxation by various tax authorities at the federal, state and local levels where we do business. New legislation could be enacted by any of these government authorities that could adversely affect our business.

In addition, from time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and natural gas exploration and production companies. Such changes have included, but have not been limited to: (i) the repeal of percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) an extension of the amortization period for certain geological and geophysical expenditures; (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies; and (v) an increase in the U.S. federal income tax rate applicable to corporations such as us. However, it is unclear whether any such changes will be enacted and, if enacted, how soon any such changes would be effective. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced demand for our products. The passage of any such legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development or could increase costs and any such changes could have an adverse effect on our business, financial condition and results of operations. Similarly, legislation could be enacted that changes or terminates the current tax incentives that our CCS projects depend on to be economical. The enactment of any legislation that reduces or eliminates 45Q credits or tax credits for the production of clean hydrogen could have an adverse effect on our business, financial condition and results of operations.

In California, there have been numerous state and local proposals for additional income, sales, excise and property taxes, including additional taxes on oil and natural gas production and a windfall profits tax on refineries. Although such proposals targeting the oil and natural gas industry have not become law, campaigns by various interest groups could lead to additional future taxes.

Financial assurance requirements related to plugging and abandonment costs, decommissioning, and site restoration on those who acquire the right to operate wells and production facilities could impact our ability to sell or acquire assets in California or increase our costs in connection with the same.

California law imposes stringent financial assurance requirements on persons who acquire the right to operate a well or production facility in California, requiring them to file either an individual indemnity bond for single-well or production facility acquisitions, or a blanket indemnity bond for multiple wells or production facilities. The bond imposed on the acquirer is an amount determined by the state to sufficiently cover plugging and abandonment costs, decommissioning, and site restoration, and California law prohibits the closing of any acquisition of the right to operate a well or production facility until a determination on the appropriate bond amount has been completed by the state and the bond has been filed. This bonding requirement significantly impacts the economic feasibility of transferring the right to operate wells and production facilities, including transfers from smaller, less-capitalized operators to more financially stable operators such as ourselves. As of the year ended December 31, 2024, our asset retirement obligations were $1,129 million, including the obligations assumed as part of the Aera Merger. This law will continue to impact our ability to grow or divest our assets within California.

Risks Related to our Indebtedness

We may not be able to amend or refinance our existing debt to create more operating and financial flexibility and to enhance shareholder returns.

Our ability to refinance our debt depends on a variety of factors, including our ability to access the commercial banking and debt capital markets. Changes in interest rates could also impact our ability to refinance our debt. If interest rates increase, the interest expense burden of any refinanced debt or other variable rate debt would increase even though the amount borrowed remained the same. There can be no assurances that we will be successful in amending, replacing or refinancing our existing debt on acceptable terms or at all.

Our existing and future indebtedness may adversely affect our business and limit our financial flexibility.

As of December 31, 2024, we had $1,132 million of total long-term debt, net and additional borrowing capacity of $983 million under the Revolving Credit Facility (after taking into account

$167 million of outstanding letters of credit). The terms of our Revolving Credit Facility and Senior Notes permit us to incur significant additional debt, some of which may be secured. Our level of future indebtedness could affect our business in several ways, including the following:

- limit management’s discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- require us to dedicate a portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities due to restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- limit our ability to pay dividends and repurchase shares;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other expenses, or to refinance existing indebtedness;
- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- make us vulnerable to increases in interest rates as our indebtedness under the Revolving Credit Facility varies with prevailing interest rates.

Our ability to satisfy our obligations depends on our future operating performance and on economic, financial, competitive and other factors, many of which are beyond our control. Our business may not generate sufficient cash flow, and future financings may not be available to provide sufficient net proceeds, to meet these obligations or to successfully execute our business strategy.

We may not be able to generate sufficient cash to service all of our indebtedness, and may be forced to take other actions to satisfy the obligations under our indebtedness, which may not be successful.

Our earnings and cash flow could vary significantly from year to year due to the nature of our industry despite our commodity price risk-management activities. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments at that time. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control as discussed in this “*Risk Factors*” section. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

The lenders under our Revolving Credit Facility could limit our ability to borrow and restrict our use or access to capital.

Our Revolving Credit Facility is an important source of our liquidity. Our ability to borrow under our Revolving Credit Facility is limited by our borrowing base, the size of our lenders’ commitments and our ability to comply with covenants.

The borrowing base under our Revolving Credit Facility is redetermined semi-annually by our lenders who review the value of our reserves and other factors that may be deemed appropriate. Currently, our borrowing base is set at $1.5 billion and the availability under our Revolving Credit Facility is limited to the aggregate elected commitment amount of our lenders, which as of February 1, 2025 is $1.15 billion.

A reduction in our borrowing base below the aggregate commitment amount of our lenders would have a material adverse effect on our liquidity and may hinder our ability to execute on our business strategy.

Restrictive covenants in our Revolving Credit Facility and the indentures governing our Senior Notes may limit our financial and operating flexibility.

Both our Revolving Credit Facility and the indentures governing our Senior Notes contain certain restrictions, which may have adverse effects on our business, financial condition or results of operations. These restrictions limit our ability to, among other things, (i) incur additional indebtedness; (ii) pay dividends or repurchase shares; (iii) sell properties; and (iv) make capital investments.

The Revolving Credit Facility also requires us to comply with certain financial maintenance covenants, including a leverage ratio and current ratio.

A breach of any of these restrictive covenants could result in a default under the Revolving Credit Facility and/or the Senior Notes. If a default occurs under the Revolving Credit Facility, the lenders may elect to declare all borrowings thereunder outstanding, together with accrued interest and other fees, to be immediately due and payable. If we are unable to repay our indebtedness when due or declared due, the lenders under the Revolving Credit Facility will also have the right to proceed against the collateral pledged to them to secure the indebtedness. An event of default under the Senior Notes may cause all outstanding Senior Notes to become due and payable immediately or give the trustee and the holders the right to declare all outstanding Senior Notes to become due and payable immediately.

Variable rate indebtedness under our Revolving Credit Facility subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Revolving Credit Facility are at variable rates of interest and expose us to interest rate risk. As of December 31, 2024, we had no amounts borrowed under our Revolving Credit Facility. If in the future we borrow under the Revolving Credit Facility, then our results of operations would be sensitive to movements in interest rates. There are many economic factors outside our control that have in the past and may, in the future, impact rates of interest including publicly announced indices that underlie the interest obligations related to our Revolving Credit Facility. Factors that impact interest rates include governmental monetary policies, inflation, economic conditions, changes in unemployment rates, international disorder and instability in domestic and foreign financial markets. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our results of operations would be adversely impacted. Such increases in interest rates could have a material adverse effect on our business, financial condition and results of operations if we borrow under the Revolving Credit Facility in the future.

Risks Related to Our Common Stock

Our ability to pay dividends and repurchase shares of our common stock is subject to certain risks.

We have adopted a cash dividend policy which anticipates a total annual dividend of $1.55 per share, payable to shareholders in quarterly increments of $0.3875 per share of common stock, subject to board authorization and declaration each quarter. Our Board of Directors authorized a share repurchase program to acquire up to $1.35 billion of our common stock through December 31, 2025. As of December 31, 2024 we had approximately $557 million of remaining authorized capacity. Any payment of future dividends or repurchasing shares of our common stock will be at the discretion of our Board of Directors and will depend upon, among other things, our earnings, liquidity, capital requirements, financial condition and other factors deemed relevant. Our Revolving Credit Facility and Senior Notes both limit our ability to pay dividends and repurchase shares of our common stock. In addition, cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. We can provide no assurances that we will continue to pay dividends at the anticipated rate or repurchase shares of our common stock within the authorized amount or at all.

The trading price of our common stock may decline, and you may not be able to resell shares of our common stock at prices equal to or greater than the price you paid or at all.

The trading price of our common stock may decline for many reasons, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. Numerous factors, including those referred to in this "*Risk Factors"* section could affect our stock price. These factors include, among other things, changes in our results of operations and financial condition; changes in commodity prices; changes in the national and global economic outlook; changes in applicable laws and regulations; variations in our capital plan; changes in financial estimates by securities analysts or ratings agencies; changes in market valuations of comparable companies; and additions or departures of key personnel.

Future issuances of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

As of December 31, 2024, we had 91,100,322 outstanding shares of common stock. We may sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities, such as in July 2024 when we issued 21,315,707 shares of common stock in connection with the Aera Merger. We expect to issue additional shares of common stock in connection with post-closing settlements for the Aera Merger. We cannot predict the size of other future issuances of our common stock or securities convertible into common stock or the effect, if any, that such other future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

The ownership position of certain of our stockholders limits other stockholders' ability to influence corporate matters and could affect the price of our common stock.

As of December 31, 2024, six of our shareholders owned at least 5% each and collectively owned approximately 57% of our common stock. As a result, each of these stockholders, or any entity to which such stockholders sell their stock, may be able to exercise significant control over matters requiring stockholder approval. Further, because of this large ownership position, if these stockholders sell their stock, the sales could depress our share price. Refer to *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Transactions Related to Our Common Stock* for information on the Registration Rights Agreement related to the Aera Merger.

Sales of shares of our common stock by our executive officers could negatively impact the market price for our common stock.

Sales of our common stock by our executive officers may adversely impact the trading price of our common stock, even when done in compliance with our policies with respect to insider sales. Although we do not expect that the relatively small volume of such sales will itself significantly impact the trading price of our common stock, the market could react negatively to the announcement of such sales, which could in turn affect the trading price of our common stock.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 1C CYBERSECURITY

We rely on information systems, computer networks and digital technologies to operate our business, including managing our operations, protecting sensitive data, communicating internally and externally, and preparing financial and operational information. Our cybersecurity program is designed to protect these critical systems and data while supporting business operations and growth objectives.

We maintain a comprehensive, risk-based approach to assess, identify and manage material risks from cybersecurity threats. Our controls are based on the NIST Cybersecurity Framework (CSF). Our cybersecurity risk management processes are integrated into our broader enterprise risk management framework and include: (i) regular assessment and monitoring of internal and external cybersecurity threats, (ii) evaluation of potential impacts on business operations, financial performance and stakeholder interests, (iii) periodic evaluation of control effectiveness to determine residual risk levels and guide program improvements, and (iv) integration of cybersecurity considerations into business strategy and technology decisions.

Our cybersecurity framework is evaluated by internal and external experts on an ongoing basis or within the scope of certain projects or engagements. Where we use third-party service providers, we endeavor to ensure that cybersecurity threats are minimized including establishing contractual protections including minimum security and breach notification requirements. We regularly evaluate and adjust these processes based on changes in the threat landscape and business environment.

In accordance with our cybersecurity incident response plan, the severity of cybersecurity incidents is classified based on the degree of adverse impact on our business, scale of penetration, risk of propagation, significance of impact, impact on protected information, and our monitoring capability. Incident response is overseen by a cybersecurity incident response team steering committee comprised of members of management with the responsibility to inform senior management and/or the Audit Committee based on incident severity classification.

The Audit Committee of our Board of Directors is responsible for overseeing our risk assessment and risk management activities, including cybersecurity risks. The Audit Committee is briefed by our Chief Digital Information Officer on cybersecurity risks at regular meetings and separately as circumstances warrant. Cybersecurity risks are also included in our enterprise risk management program which is reported separately to the Audit Committee. We maintain a dedicated cybersecurity team responsible for program implementation and operational security activities.

Our Chief Digital Information Officer has managerial responsibility for our cybersecurity risk program and is a member of our cybersecurity incident response team. Our Chief Digital Information Officer has over 27 years of experience in information technology, including leadership roles responsible for cybersecurity and data privacy. He graduated from California State University, Bakersfield with a Bachelor of Science degree in Computer Science.

As of the date of this report, we are not aware of any material risks from cybersecurity threats that have materially affected or are reasonably likely to materially affect our business strategy, results of operations, or financial condition.

ITEM 3 LEGAL PROCEEDINGS

For information regarding legal proceedings, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Lawsuits, Claims, Commitments and Contingencies* and *Part II, Item 8 – Financial Statements and Supplementary Data – Note 6 Lawsuits, Claims, Commitments and Contingencies*.

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information for Common Stock

Our common stock is traded under the symbol "CRC" on the New York Stock Exchange (NYSE).

Holders of Record

Our common stock was held by 9 stockholders of record at January 31, 2025, which does not include the beneficial owners for whom Cede and Co. or others act as nominees.

Dividend Policy

Our Board of Directors has approved a cash dividend policy that contemplates a total annual dividend of $1.55 per share of common stock, payable to stockholders in quarterly increments of $0.3875 per share. This includes a recent amendment in August 2024 to our prior dividend policy that contemplated a total quarterly dividend of $0.31 per share of common stock. Changes to our dividend policy and all dividends are subject to approval by our Board of Directors and will be determined based on conditions including our earnings, liquidity, capital requirements, financial condition, restrictions under our Revolving Credit Facility and Senior Notes and other factors.

Share Repurchases

Our Board of Directors authorized a Share Repurchase Program to acquire up to $1.35 billion of our common stock through December 31, 2025. Our Share Repurchase Program does not obligate us to acquire any number of shares and may be discontinued at any time. For further information regarding our Share Repurchase Program, see *Part II, Item 7 – Management's Discussion and Analysis of Financial Results of Operations, Transactions Related to Our Common Stock.* Our share repurchase activity for the year ended December 31, 2024 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs[a]
January 1, 2024 - March 31, 2024	1,065,764	$ 53.26	1,065,764	$ —
April 1, 2024 - June 30, 2024	703,839	$ 49.71	703,839	—
July 1, 2024 - September 30, 2024	835,319	$ 50.23	835,319	—
October 1, 2024 - October 31, 2024	391,498	$ 52.36	391,498	—
November 1, 2024 - November 30, 2024	292,947	$ 56.84	292,947	—
December 1, 2024 - December 31, 2024	359,981	$ 53.69	359,981	—
Total 2024	3,649,348	$ 52.12	3,649,348	$ —

(a) The remaining capacity for shares that may be acquired under our Share Repurchase Program was $557 million as of December 31, 2024.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes the securities available for issuance under equity compensation plans as of December 31, 2024. A description of our stock-based compensation plans can be found in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation*.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders(1)	1,250,000	—	1,154,250
Equity compensation plan not approved by security holders(2)	2,052,457	—	5,277,415
Total	3,302,457		6,431,665

(1) Reflects shares available under our Employee Stock Purchase Plan for purchase at 85% of the lower of the market price at either (i) the beginning of a quarter or (ii) the end of a quarter.

(2) The aggregate number of 9,257,740 shares of our common stock authorized for issuance under our Long-Term Incentive Plan were approved by the Bankruptcy Court as part of the joint plan of reorganization upon our emergence from bankruptcy in 2020. The number of securities to be issued upon vesting of performance stock units assumes all units are earned upon either (i) achieving the specified 60-trading day volume weighted average prices for shares of our common stock or (ii) the absolute total shareholder return and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation* for more information on these awards.

Performance Graph

The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer group. The graph assumes that on October 28, 2020, $100 was invested in our common stock and in each of the peer group companies' common stock weighted by their relative market capitalization, or invested on October 31, 2020 in an index, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

Our 2024 peer group consisted of Antero Resources Corporation; APA Corporation; Berry Corporation; BKV Corporation; Chord Energy Corporation; Civitas Resources, Inc.; Comstock Resources Inc.; Crescent Energy Company; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources Company; Murphy Oil Corporation; Permian Resources Corporation; Range Resources Corporation; Sable Offshore Corporation; SM Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

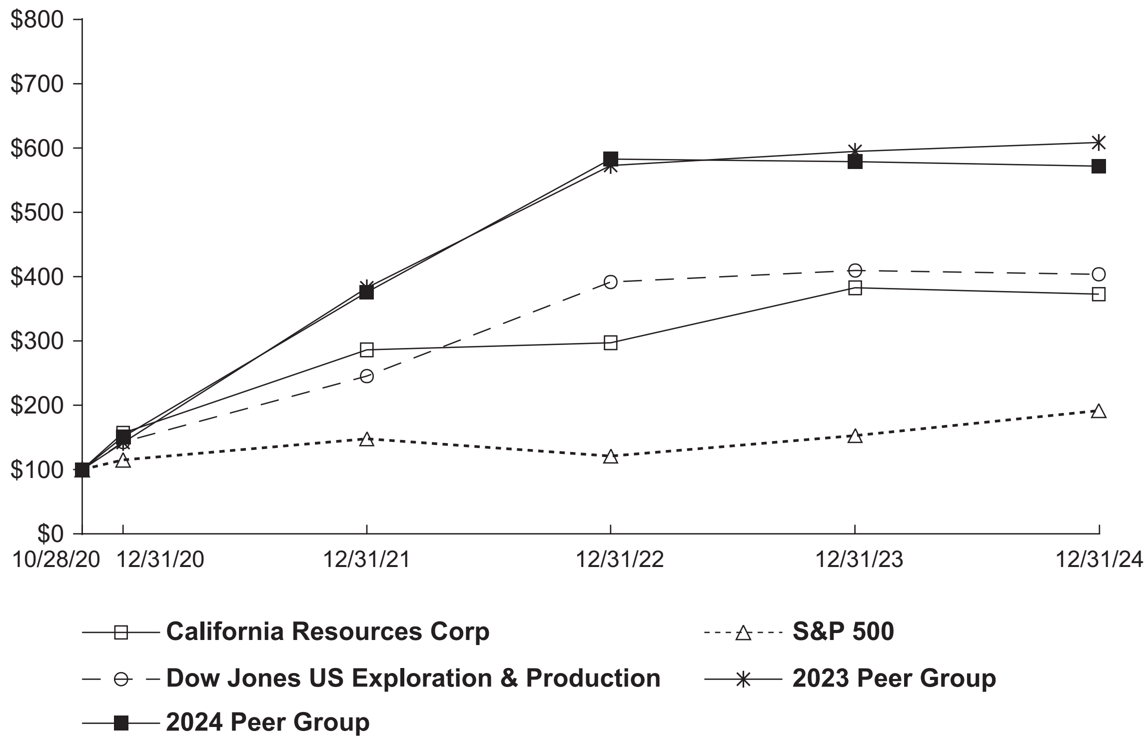
Our peer group changed from 2023. We added BKV Corporation which is a new public company with similar operations and presence in the carbon sequestration sector in the United States. We also added APA Corporation and Sable Offshore Corporation to our peer group due to their similar market capitalization and area of operations. We removed Callon Petroleum Company and Southwestern Energy Company from our peer group after they were acquired in 2024.

Our 2023 peer group consisted of Antero Resources Corporation; Berry Corporation; Callon Petroleum Company; Chord Energy Corporation; Civitas Resources, Inc.; Comstock Resources Inc.; Crescent Energy Company; Kosmos Energy Ltd.; Magnolia Oil & Gas Corp; Matador Resources

Company; Murphy Oil Corporation; Permian Resources Corporation; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; Talos Energy Inc.; and Vermilion Energy Inc.

PERFORMANCE GRAPH*

Among California Resources Corp, the S&P 500 Index,
the Dow Jones US Exploration & Production Index,
2023 Peer Group and 2024 Peer Group



*$100 invested on 10/28/20 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	10/28/20	12/31/20	12/31/21	12/31/22	12/31/23	12/31/24
California Resources Corp	**$100.00**	**$157.27**	**$285.97**	**$296.45**	**$381.98**	**$372.19**
S&P 500	**$100.00**	**$115.21**	**$148.28**	**$121.43**	**$153.35**	**$191.72**
Dow Jones US Exploration & Production	**$100.00**	**$143.37**	**$245.05**	**$391.02**	**$408.69**	**$402.47**
2023 Peer Group	**$100.00**	**$141.85**	**$381.68**	**$570.92**	**$592.79**	**$606.14**
2024 Peer Group	**$100.00**	**$151.36**	**$374.38**	**$580.42**	**$577.26**	**$569.81**

* This performance graph shall not be deemed "soliciting material" or to be "filed" with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of CRC under the Securities Act of 1933, as amended, or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

ITEM 6 RESERVED

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

The following discussion should be read in conjunction with other sections of this report, including but not limited to, *Part I, Item 1 and 2 – Business and Properties* and *Part II, Item 8 – Financial Statements and Supplementary Data.*

See *Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations* in our Annual Report on Form 10-K for the year ended December 31, 2023 (2023 Annual Report) for our analysis of the changes in our consolidated statements of operations and statements of cash flows for the year ended December 31, 2023 compared to December 31, 2022.

Basis of Presentation

All financial information presented consists of our consolidated results of operations, financial position and cash flows unless otherwise indicated. We have eliminated all intercompany transactions and accounts. We account for our share of oil and natural gas production activities, in which we have a direct working interest by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our balance sheets and statements of operations and cash flows. In applying the equity method of accounting, our investments in our unconsolidated subsidiaries are recognized either at cost, as is the case with Carbon TerraVault JV HoldCo, LLC, or at fair value if acquired in a business combination, as is the case for Midway Sunset Cogeneration Company. These investments are then adjusted for our proportionate share of income or loss in addition to contributions and distributions.

Certain prior period balances related to NGL marketing activities were reclassified to conform to our 2024 presentation. For the year ended December 31, 2023, we reclassified $6 million related to NGL storage activities from other revenue to revenue from marketing of purchased commodities and we reclassified $3 million related to NGL processing fees from other operating expenses, net to costs related to marketing of purchased commodities on our consolidated statement of operations.

Aera Merger

Following the closing of the Aera Merger, in August 2024 we initiated a workforce reduction to align the size and composition of our workforce with expected future operations and to capture synergies related to Aera Merger. As a result, we reduced our combined company's employee headcount by 12% and recognized a charge of $30 million in other operating expenses, net on the consolidated statement of operations for the year ended December 31, 2024, respectively, primarily related to severance benefits. We expect to pay the remaining severance costs through 2026 as the workforce reduction will be achieved in stages due to transition periods. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger* for information on the severance plan and *Note 14 Pension and Postretirement Benefit Plans* for information on amendments to Aera's pension and postretirement benefit plans.

Statement of Operations Analysis

Consolidated Results of Operations

Our consolidated results of operations include the results of Aera beginning July 1, 2024, the closing date of the Aera Merger. For more information on the Aera Merger, see *Part I, Item 1 and 2 – Business and Properties, Business* and *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger.* The Aera Merger and related transactions have significantly impacted the comparability of our financial results for 2024 and prior years.

For financial information related to our subsidiaries designated as Unrestricted Subsidiaries under the 2026 Senior Notes Indenture and 2029 Senior Notes Indenture, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 18 Condensed Consolidating Financial Information.*

Year Ended December 31, 2024 vs. 2023

The following table presents our total operating revenues:

	Year ended December 31, 2024	Year ended December 31, 2023
	(in millions)	
Oil, natural gas and NGL sales	$ 2,537	$ 2,155
Net gain (loss) from commodity derivatives	241	(12)
Revenue from marketing of purchased commodities	235	407
Electricity sales	159	211
Interest and other revenue	26	40
Total operating revenues	$ 3,198	$ 2,801

Oil, natural gas and NGL sales – Oil, natural gas and NGL sales, excluding the impact of payments on settled commodity derivatives, were $2,537 million for the year ended December 31, 2024, which is an increase of $382 million from $2,155 million for the year ended December 31, 2023. This increase includes $915 million of oil, natural gas and NGL sales related to additional production from the Aera fields following the completion of the Aera Merger on July 1, 2024. Excluding the Aera fields, our oil, natural gas and NGL sales were lower in the year ended December 31, 2024 compared to the same prior year period primarily due to lower natural gas prices. The effect of cash settlements on our commodity derivative contracts are excluded from the table below.

	Oil	NGLs	Natural Gas	Total
		(in millions)		
Year ended December 31, 2023	$ 1,534	$ 198	$ 423	$ 2,155
Changes in realized prices	(66)	—	(276)	(342)
Changes in production and other	787	(12)	(51)	724
Year ended December 31, 2024	$ 2,255	$ 186	$ 96	$ 2,537

Note: See *Production, Prices and Realizations* for volumes and realized prices by commodity type for each period.

Net gain (loss) from commodity derivatives – We report gains and losses on our derivative contracts related to our oil production and marketing activities in operating revenue. Net gain from commodity derivatives was $241 million for the year ended December 31, 2024 compared to a net loss of $12 million for the year ended December 31, 2023. The change primarily resulted from payments to settle commodity derivative contracts and the non-cash changes in the fair value of our outstanding commodity derivatives from the positions held at the end of each measurement period. Gains and losses from our commodity derivative contracts are shown in the table below:

	Year ended December 31, 2024	Year ended December 31, 2023
	(in millions)	
Non-cash commodity derivative gain	$ 274	$ 260
Settlements and amortized premiums	(33)	(272)
Net gain (loss) from commodity derivatives	$ 241	$ (12)

Revenue from marketing of purchased commodities – Revenue from marketing of purchased commodities was $235 million during the year ended December 31, 2024, which is a decrease of $172 million from $407 million during the year ended December 31, 2023. The decrease was primarily a result of lower natural gas prices in 2024 compared to 2023, and was partially offset by higher sales of purchased crude oil in 2024 as compared to 2023. Our margin from marketing of purchased commodities was $42 million for the year ended December 31, 2024 compared to $183 million for the year ended December 31, 2023.

Electricity sales – Electricity sales decreased by $52 million to $159 million during the year ended December 31, 2024 compared to $211 million for the year ended December 31, 2023. The decrease was predominantly due to lower electricity prices in 2024 as well as scheduled maintenance and unplanned downtime at our Elk Hills power plant.

The following table presents our consolidated operating expenses, non-operating expenses and income tax provision:

	Year ended December 31, 2024	Year ended December 31, 2023
	(in millions)	
Operating expenses		
Energy operating costs	$ 279	$ 323
Non-energy operating costs	671	481
Gas processing costs	16	18
General and administrative expenses	321	267
Depreciation, depletion and amortization	388	225
Asset impairments	14	3
Taxes other than on income	242	165
Costs related to marketing of purchased commodities	193	224
Electricity generation expenses	40	103
Transportation costs	81	67
Accretion expense	87	46
Net loss on natural gas purchase derivatives	30	8
Carbon management business expenses	56	37
Measurement period adjustments	(12)	—
Other operating expenses, net	183	58
Total operating expenses	$ 2,589	$ 2,025
Gain on asset divestitures	11	32
Operating income	620	808
Non-operating (expenses) income		
Interest and debt expense	(87)	(56)
Loss on early extinguishment of debt	(5)	(1)
Loss from investment in unconsolidated subsidiaries	(10)	(9)
Other non-operating (loss) income	(2)	6
Income before income taxes	516	748
Income tax provision	(140)	(184)
Net income	$ 376	$ 564

Energy operating costs consist of purchased natural gas used to generate electricity for our operations and steam for our steamfloods, purchased electricity and internal costs to generate electricity used in our operations. Gas processing costs include costs associated with compression, maintenance and other activities needed to run our gas processing facilities at Elk Hills. Non-energy operating costs equal total operating costs less energy operating costs and gas processing costs.

Energy operating costs – Energy operating costs for the year ended December 31, 2024 were $279 million, which was a decrease of $44 million from $323 million for the year ended December 31, 2023. Excluding $95 million related to the operation of the Aera fields, our energy operating costs for the year ended December 31, 2024 would have been $184 million. This decrease was primarily a result of lower natural gas prices in the year ended December 31, 2024 compared to the same prior year period. For more information on our natural gas market prices, see *Segment Results of Oil and Natural Gas Operations, Production, Prices and Realizations* below.

Non-energy operating costs – Non-energy operating costs for the year ended December 31, 2024 were $671 million, which was an increase of $190 million from $481 million for the year ended December 31, 2023. The increase was predominately a result of costs related to the additional fields acquired in the Aera Merger. Non-energy operating costs for the year ended December 31, 2024 include $206 million related to Aera's operations. Excluding costs related to the Aera fields, non-energy operating costs for the year ended December 31, 2024 were lower than the prior year period as a result of lower costs for downhole and surface maintenance and more favorable vendor pricing for certain items in 2024 as a result of cost savings initiatives undertaken during 2023.

General and administrative expenses – General and administrative expenses were $321 million for the year ended December 31, 2024, which was an increase of $54 million from $267 million for the year ended December 31, 2023. The increase was primarily a result of an additional $73 million of expenses related to Aera for the period from July 1, 2024 through December 31, 2024. Excluding Aera, general and administrative expenses were lower in the year ended December 31, 2024 compared to the year ended December 31, 2023 as a result of reduced spending on information technology infrastructure and lower compensation-related expense, including stock-based compensation expense. Stock-based compensation awards are discussed further below.

Awards are granted under our stock-based compensation plans to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include performance stock units and restricted stock units that either cliff vest or vest ratably over a two- or three-year period. Our equity-settled awards granted to non-employee directors are restricted stock units that vest ratably over a three-year period. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduce volatility in our results of operations because we pay half of our cash-settled awards based on our stock price performance and we adjust our obligation for unvested cash-settled awards at the end of each reporting period. Equity-settled awards are not similarly adjusted for changes in our stock price.

Stock-based compensation included in G&A expense is shown in the table below:

	Year ended December 31,	
	2024	**2023**
	(in millions)	
Cash-settled awards	$ 9	$ 13
Stock-settled awards	23	27
Total included in general and administrative expenses	$ 32	$ 40

Depreciation, depletion and amortization – Depreciation, depletion and amortization increased $163 million to $388 million for the year ended December 31, 2024 from $225 million for the same prior year period. The increase was primarily the result of a higher net book value for our property, plant and equipment as a result of the Aera Merger.

Taxes other than on income – Taxes other than on income increased $77 million to $242 million for the year ended December 31, 2024 from $165 million for the year ended December 31, 2023. The increase was a result of higher greenhouse gas expense, production taxes and ad valorem taxes related to the Aera assets following the completion of the Aera Merger.

Costs related to marketing of purchased commodities – Costs related to marketing of purchased commodities was $193 million for the year ended December 31, 2024, which was a decrease of $31 million from $224 million for the year ended December 31, 2023 primarily due to lower natural gas prices. This decrease was partially offset by additional costs related to increased purchased crude oil used in certain of our marketing activities in 2024 as compared to 2023.

Electricity generation expense – Electricity generation expenses decreased to $40 million for the year ended December 31, 2024 from $103 million for the year ended December 31, 2023. The decrease of $63 million was predominantly a result of lower prices for natural gas used in electricity generation and scheduled maintenance and unplanned downtime at our Elk Hills power plant in the first half of 2024.

Accretion expense – Accretion expense was $87 million for the year ended December 31, 2024, which was an increase of $41 million from $46 million for the year ended December 31, 2023. The increase was primarily due to asset retirement obligations assumed as of July 1, 2024 as part of the Aera Merger.

Net loss on natural gas purchase derivatives – Net loss on natural gas purchase derivatives was $30 million for the year ended December 31, 2024. For the same prior year period, we recognized a net loss of $8 million. The change primarily resulted from payments to settle commodity derivative contracts and the non-cash changes in the fair value of our outstanding commodity derivatives from the positions held at the end of each measurement period. Gains and losses from our commodity derivative contracts are shown in the table below. For more information on our derivatives, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives.*

	Year ended December 31, 2024	Year ended December 31, 2023
	(in millions)	
Non-cash (gain) loss on natural gas purchase derivatives	$ (2)	$ 8
Settlements	32	—
Net loss on natural gas purchase derivatives	$ 30	$ 8

Other operating expenses, net – Other operating expenses, net were $183 million for the year ended December 31, 2024, which was an increase of $125 million from $58 million for the year ended December 31, 2023. The increase was primarily a result of transaction and integration costs for the Aera Merger of $57 million as well as additional expenses related to electricity purchased during the ongoing maintenance and downtime at our Elk Hills power plant of $50 million. We also incurred higher severance costs in the year ended December 31, 2024 as a result of the headcount reduction following the Aera Merger.

Gain on asset divestitures – Our gain on asset divestitures for the year ended December 31, 2024 was $11 million primarily related to the divestiture of non-core assets and the completion of our Ventura divestiture. Gain on asset divestitures for the year ended December 31, 2023 was $32 million primarily related to the divestiture of our non-operated portion of the Round Mountain Unit. For more information on our asset divestitures, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions.*

Interest and debt expense, net – Interest and debt expense, net was $87 million for the year ended December 31, 2024, which was an increase of $31 million from $56 million for the year ended December 31, 2023. The increase was predominately a result from higher interest expense from the issuance of our 2029 Senior Notes. In June 2024, we issued $600 million in aggregate principal amount of 8.25% senior notes due 2029 and in August 2024, we completed a follow-on offer of $300 million in aggregate principal amount for those notes. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt* for information on financing costs related to the Aera Merger.

Income tax provision – The income tax provision for the year ended December 31, 2024 was $140 million (effective tax rate of 27%) compared to $184 million (effective tax rate of 25%) for the year ended December 31, 2023. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 8 Income Taxes* for more information for on our effective tax rate.

Segment Results of Oil and Natural Gas Operations

The following tables include results for our oil and natural gas segment, excluding unallocated corporate expenses for the years ended December 31, 2024, 2023 and 2022. Our results of operations for the oil and natural gas segment include the financial and operating results of Aera beginning on July 1, 2024, the closing date of the Aera Merger. For more information on the Aera Merger, see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger.*

	Year ended December 31,		
	2024	**2023**	**2022**
	(in millions, except as otherwise stated)		
Net production sold (MBoe/d)	110	86	91
Segment total operating revenue	$ 2,572	$ 2,172	$ 2,660
Segment profit	815	$ 922	$ 1,537
Items affecting comparability:			
Asset impairments[(a)]	$ 13	$ —	$ —
Net gain on asset divestitures[(b)]	$ 10	$ 32	$ 59

(a) Asset impairment for the year ended December 31, 2024 related to the write-off of excess and obsolete materials and supplies, generally requisitioned for wells and capitalized as part of drilling and completion activities. The table above excludes asset impairments that were not related to the oil and natural gas segment.

(b) Gain on asset divestitures for the year ended December 31, 2024 related to the sale of our 0.9-acre Fort Apache real estate property in Huntington Beach, California as well as the remaining portion of our Ventura assets which were classified as held for sale. Gain on asset divestitures for the year ended December 31, 2023 related to the sale of our non-operated interest in the Round Mountain Unit and a non-producing asset in exchange for the assumption of liabilities. Net gain on asset divestitures for the year ended December 31, 2022 related to the sale of our 50% non-operated working interest in certain horizons within our Lost Hills field and the divestiture of certain Ventura basin assets. The table above excludes net gain on asset divestitures that were not related to the oil and natural gas segment.

	Year ended December 31,		
	2024	**2023**	**2022**
	($ per Boe)		
Energy operating costs	$ 7.38	$ 10.31	$ 9.76
Non-energy operating costs	16.73	15.35	13.47
Gas processing costs	0.40	0.58	0.52
Operating costs	$ 24.51	$ 26.24	$ 23.75
Operating costs, after hedges	$ 25.31	$ 26.24	$ 23.75
Field general and administrative expenses[(a)]	$ 1.07	$ 1.34	$ 1.09
Field depreciation, depletion and amortization[(b)]	$ 8.83	$ 6.61	$ 5.29
Field taxes other than on income	$ 5.16	$ 3.61	$ 3.36
Field transportation expenses	$ 0.90	$ 0.99	$ 0.85

(a) Excludes unallocated general and administrative expenses.

(b) Excludes depreciation, depletion and amortization related to our corporate assets and Elk Hills power plant.

Energy costs in total and on a per Boe basis were lower in the year ended December 31, 2024 compared to the prior year period primarily as a result of lower natural gas prices. Energy operating costs were higher on a per Boe basis in for the year ended December 31, 2023 compared to the year ended December 31, 2022 as a result of lower production volumes in 2023.

We entered into commodity derivative contracts for purchased natural gas and acquired additional commodity derivative contracts in the Aera Merger. During the year ended December 31, 2024, we paid $32 million in settlement payments on natural gas derivatives, increasing our operating costs by $0.80 per Boe as shown in the table above. Our hedge contracts are part of our marketing function and hedge settlements are generally not allocated to our oil and gas segment. However, we believe it is useful to present our operating costs after hedge settlements.

In 2025, our hedges for purchased natural gas approximate 62% of our expected fuel use in oil and natural gas operations. These 2025 hedges have a weighted average price of approximately $3.95 per MMBtu. Aera entered into natural gas hedges prior to our acquisition, and as of December 31, 2024, the weighted average price of those remaining hedges was $5.67 and we expect to pay $13 million to settle all of these contracts in the three months ended March 31, 2025.

Non-energy operating costs were higher in total and on a per Boe basis for the year ended December 31, 2024 compared to the year ended December 31, 2023 as a result of the Aera Merger on July 1, 2024. For the year ended December 31, 2024, non-energy operating costs related to the Aera fields predominately related to additional downhole maintenance and surface operations maintenance activity. Excluding the Aera fields, we had lower non-energy operating costs for the year ended December 31, 2024 compared to the same prior year period as a result of cost savings initiatives we implemented at the end of 2023. Non-energy operating costs were higher for the year ended December 31, 2023 compared to the year ended December 31, 2022 on a per Boe basis due to higher compensation-related costs for field personnel and additional downhole maintenance activity for the year ended December 31, 2023.

Operating costs, including the effects of natural gas hedges included settlement payments related to purchased natural gas used in our steamflood operations. We assumed natural gas hedges as part of the Aera Merger. We did not have settlements related to purchased natural gas hedges in the years ended December 31, 2023 and 2022.

Field depreciation, depletion and amortization increased for the year ended December 31, 2024 compared to the year ended December 31, 2023 as a result of the completion of the Aera Merger. Field depreciation, depletion and amortization increased for the year ended December 31, 2023 compared to the prior year primarily due to a change in our depreciation, depletion and amortization rates which are periodically adjusted to reflect an update of our SEC reserve estimates. Lower production volumes also contributed to the increase on a per Boe basis.

Field taxes other than on income were higher for the year ended December 31, 2024 compared to the same prior year period predominately as a result of the Aera Merger. Field taxes other than on income were higher in the year ended December 31, 2023 on a per Boe basis, due to lower production volumes compared to the year ended December 31, 2022.

Production, Prices and Realizations

The amounts in the production tables below include volumes produced from Aera's operated and non-operated fields during the period from July 1, 2024 through December 31, 2024 and volumes from CRC's operated and non-operated fields for each of the periods presented.

The following table sets forth our average net production of oil, NGLs and natural gas sold per day in each of the California oil and natural gas basins in which we operate for the years ended December 31, 2024, 2023 and 2022:

	Year ended December 31,		
	2024	2023	2022
Oil (MBbl/d)	80	52	55
NGLs (MBbl/d)	10	11	11
Natural gas (MMcf/d)	117	135	147
Total Daily Net Production (MBoe/d)	110	86	91

The following table summarizes the changes to our total daily net production per day for the periods presented:

	Year ended December 31,		
	2024	2023	2022
		(MBoe/d)	
Beginning of the year	86	91	100
Divestitures[(a)]	(1)	—	(5)
Plant downtime[(b)]	(2)	—	(1)
Acquisitions[(c)]	34	—	1
PSC effect	—	1	—
Natural decline and other	(7)	(6)	(4)
Total change	24	(5)	(9)
End of the year	110	86	91

(a) See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* for more information. Note that for the year ended December 31, 2023, our divestitures did not have a significant impact on our production volumes because the sale of our non-operated working interest in the Round Mountain Unit closed on December 29, 2023 and we sold a non-producing asset during the year.

(b) Included scheduled maintenance and unplanned downtime at our Elk Hills power plant for the year ended December 31, 2024. In the first quarter of 2022, we conducted routine maintenance at one of our gas processing facilities.

(c) We completed the Aera Merger on July 1, 2024 and the amount of production shown in the table above is averaged over a 12-month period. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger* for more information.

Our operating results and those of the oil and natural gas industry as a whole are heavily influenced by commodity prices. Global commodity prices decreased during the year ended December 31, 2024 compared to the year ended December 31, 2023 predominately as a result of growing inventories and decreased demand. Oil and natural gas prices and differentials may fluctuate significantly as a result of numerous market-related variables. These and other factors make it impossible to predict realized prices reliably. The following tables set forth average benchmark prices, average realized prices and price realizations as a percentage of average benchmark prices for our products for the periods indicated below:

	2024		2023		2022	
	Average Price	Realization	Average Price	Realization	Average Price	Realization
Oil ($ per Bbl)						
Brent	$ 79.84		$ 82.22		$ 98.89	
Realized price without derivative settlements	$ 76.92	96%	$ 80.41	98%	$ 98.26	99%
Effects of derivative settlements	(1.26)		(14.44)		(36.46)	
Realized price with derivative settlements	$ 75.66	95%	$ 65.97	80%	$ 61.80	62%
WTI	$ 75.72		$ 77.62		$ 94.23	
Realized price without derivative settlements	$ 76.92	102%	$ 80.41	104%	$ 98.26	104%
Realized price with derivative settlements	$ 75.66	100%	$ 65.97	85%	$ 61.80	66%
NGLs ($ per Bbl)						
Realized price[(a)]	$ 48.93	61%	$ 48.94	60%	$ 64.33	65%
Realized price[(b)]	$ 48.93	65%	$ 48.94	63%	$ 64.33	68%
Natural gas						
NYMEX ($/MMBTU) - Average Monthly Settled Price	$ 2.27		$ 2.74		$ 6.64	
Realized price without derivative settlements ($/Mcf)	$ 2.99	132%	$ 8.59	314%	$ 7.68	116%
Effects of derivative settlements	—		—		(0.14)	
Realized price with derivative settlements ($/Mcf)	$ 2.99	132%	$ 8.59	314%	$ 7.54	114%

(a) Calculated as a percentage of Brent.
(b) Calculated as a percentage of WTI.

Oil — Brent and realized prices excluding derivative settlements were lower for the year ended December 31, 2024 compared to the same prior year period. The decrease was largely a result of slowing global demand growth, increased production from non-OPEC+ countries, and an awareness that OPEC+ could remove voluntary production cuts at any time. Including derivative settlements, our realized price increased for the year ended December 31, 2024 compared to the prior year.

NGLs — Prices for NGLs were flat for the year ended December 31, 2024 compared to the same prior year period. NGL prices fluctuate with the seasons of the year but remained flat between years as a result of increased supply, solid demand and an absence of protracted abnormal weather. California markets continued to carry a premium to other markets in 2024.

Natural Gas — Realized natural gas prices for the year ended December 31, 2024 were lower than those for the year ended December 31, 2023 influenced primarily by higher storage inventories, abundant import availability and a general lack of unseasonable weather. The year ended December 31, 2023 included a historic spike in pricing during the first quarter of 2023, while the rest of the year declined in price.

Results of Our Carbon Management Segment

Our carbon management segment, which we refer to as Carbon TerraVault, pursues the development of carbon capture and sequestration projects. We expect that our Carbon TerraVault CCS projects will inject CO_2 captured from industrial, power, agriculture and other emissions sources into subsurface reservoirs and permanently store CO_2 deep underground. We also expect to invest in projects that rely on CCS technology in connection with reducing our own emissions. In addition, we may participate in the development of projects that are the source of these CO_2 emissions. Our carbon management segment is in its early stages of development, and did not have any revenue for the years ended December 31, 2024, 2023 or 2022. We define carbon management expense to be our direct operating costs to run our carbon management segment.

The following tables include results for our carbon management segment, excluding unallocated corporate expenses for the years ended December 31, 2024, 2023 and 2022.

	Year ended December 31,		
	2024	2023	2022
	(in millions, except as otherwise stated)		
Segment loss	$ (94)	$ (66)	$ (41)
Items affecting comparability:			
Asset impairments[(a)]	$ 1	$ 3	$ —

(a) Asset impairment for the years ended December 31, 2024 and 2023 related to land acquired for our carbon management activities. The table above excludes asset impairments that were not related to the carbon management segment.

We recognized losses for the years ended December 31, 2024, 2023 and 2022 related to our Carbon TerraVault joint venture, as shown in the table below. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our Carbon TerraVault joint venture. Carbon management expense and general and administrative expense for the years ended December 31, 2024, 2023 and 2022 are included in the table below.

	Year ended December 31,		
	2024	2023	2022
	(in millions)		
Carbon management expense	$ 56	$ 37	$ 14
General and administrative expense	$ 15	$ 12	$ 12
Loss from investment in unconsolidated subsidiary	$ 12	$ 9	$ 1

Carbon management expenses increased in 2024 compared to 2023 as a result of additional compensation-related costs as more development work was performed and employee headcount increased as we realigned our job functions during our August 2024 reorganization. During the year ended December 31, 2024, we also incurred additional costs related to easements and pre-construction activities.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity and capital resources are cash flows from operations, cash and cash equivalents and available borrowing capacity under our Revolving Credit Facility. We consider our low leverage and ability to control costs to be a core strength and strategic advantage, which we are focused on maintaining. Our primary uses of operating cash flow for the year ended December 31, 2024 were for capital investments, repurchases of our outstanding debt and common stock, and payment of dividends.

The following table summarizes our liquidity:

	December 31, 2024
	(in millions)
Available cash and cash equivalents[(a)]	$ 354
Revolving Credit Facility:	
Borrowing capacity	1,150
Outstanding letters of credit	(167)
Availability	$ 983
Liquidity	$ 1,337

(a) Excludes restricted cash of $18 million.

At current commodity prices and based upon our planned 2025 capital program described below, we expect to generate operating cash flow to support and invest in our core assets and preserve financial flexibility. We regularly review our financial position and evaluate whether to (i) adjust our drilling program, (ii) return available cash to shareholders through dividends or stock repurchases to the extent permitted under our Revolving Credit Facility and the indentures for our 2026 Senior Notes and our 2029 Senior Notes, (iii) reduce outstanding indebtedness, (iv) advance carbon management activities, or (v) maintain cash and cash equivalents on our balance sheet. We also intend to pursue financing options to further develop our carbon management segment. We believe we have sufficient sources of liquidity to meet our obligations for the next twelve months.

Derivatives

Significant changes in oil and natural gas prices may have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow, and the inverse applies during periods of rising commodity prices. Our hedging strategy seeks to mitigate our exposure to commodity price volatility and ensure our financial strength and liquidity by protecting our cash flows. We will continue to evaluate our hedging strategy based upon prevailing market prices and conditions.

Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as cash-flow or fair-value hedges. We did not have any commodity derivatives designated as accounting hedges as of and for the year ended December 31, 2024.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives* for more information on our open derivative contracts as of December 31, 2024 and *Note 5 Debt* for more information on the hedging requirements included in our Revolving Credit Facility.

Long-Term Debt

Our long-term debt consists of borrowings and indebtedness under our Revolving Credit Facility, 2026 Senior Notes and 2029 Senior Notes. For more information regarding our Revolving Credit Facility, 2026 Senior Notes and 2029 Senior Notes, refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt.*

Revolving Credit Facility

On April 26, 2023, we entered into an Amended and Restated Credit Agreement (Revolving Credit Facility) with Citibank, N.A., as administrative agent, and certain other lenders, which amended and restated in its entirety the prior credit agreement dated October 27, 2020. As of December 31, 2024, we were in compliance with all of the covenants of our Revolving Credit Facility.

Recent Amendments

In 2024, we entered into the following amendments to our Revolving Credit Facility:

- February 2024 – we entered into a second amendment that, among other things, permit the incurrence of indebtedness under a bridge loan facility in connection with the Aera Merger.
- March 2024 – we entered into a third amendment that facilitated certain matters with respect to the Aera Merger, including the postponement of the regular spring borrowing base redetermination until the fall of 2024 and certain other amendments.
- July 1, 2024 – we entered into a fourth amendment that increased the aggregate revolving commitments available under the Revolving Credit Facility from $630 million to $1.1 billion. This amendment also increased the borrowing base from $1.2 billion to $1.5 billion, among other matters.
- November 1, 2024 – we entered into a fifth amendment that, among other things, extended the maturity date of the Revolving Credit Facility to March 16, 2029 and amended the springing maturity provisions, increased our capacity to issue letters of credit by $50 million to $300 million, and increased the aggregate amount of revolving commitment by $50 million to $1,150 million. Our borrowing base of $1.5 billion is redetermined semi-annually and was re-affirmed in November 2024 as part of our recent amendment.

2029 Senior Notes

On June 5, 2024, we completed an offering of $600 million in aggregate principal amount of 8.25% senior notes due 2029 (2029 Senior Notes). The terms of the 2029 Senior Notes are governed by the Indenture, dated as of June 5, 2024, by and among us, the guarantors and Wilmington Trust, National Association, as trustee (2029 Senior Notes Indenture). The net proceeds of $590 million, after $10 million of debt discount and issuance costs, were used along with available cash to repay all of Aera's outstanding debt at closing of the Aera Merger.

On August 22, 2024, we completed a follow-on offering of $300 million in aggregate principal amount of 2029 Senior Notes. The net proceeds from this offering of $298 million, after $3 million of debt premium and $5 million of debt issuance costs, were used to repurchase a portion of our outstanding 7.125% senior notes due 2026 (2026 Senior Notes) as described below. The follow-on 2029 Senior Notes issued on August 22, 2024 are governed by the same indenture as the $600 million of 2029 Senior Notes that were previously issued on June 5, 2024.

2026 Senior Notes

On January 20, 2021, we completed an offering of $600 million in aggregate principal amount of our 7.125% senior unsecured notes due 2026. The net proceeds of $587 million, after $13 million of debt issuance costs, were used to repay our outstanding indebtedness.

In the year ended December 31, 2024, we repurchased $300 million in face value of our 2026 Senior Notes for $303 million, resulting in a loss on early extinguishment of debt in the amount of $5 million which includes a $2 million write-off of unamortized debt issuance costs. In the year ended December 31, 2023, we repurchased $55 million in face value of our 2026 Senior Notes at par resulting in an extinguishment loss of $1 million for the write-off of unamortized debt issuance costs.

Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 19 Subsequent Events* for information on a recent repurchase of our 2026 Senior Notes.

Transactions Related to Our Common Stock

The following table is a summary of changes in our outstanding shares of our common stock during the year ended December 31, 2024:

	Common Stock
Balance at December 31, 2023	68,693,885
Issued as part of the Aera Merger	21,315,707
Shares issued for warrant exercises	3,769,703
Shares issued under ESPP	38,257
Shares issued under stock-based compensation arrangements[a]	1,740,189
Treasury stock - shares repurchased	(3,649,348)
Shares cancelled for taxes	(808,071)
Balance at December 31, 2024	91,100,322

(a) A significant number of stock-based compensation awards were settled in the first quarter of 2024. These awards were primarily granted in January 2021 following our emergence from bankruptcy.

We expect to issue additional shares during 2025 to Sellers in connection with the acquisition of Aera related to the settlement of pre-acquisition income taxes. Refer to *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger* for additional information.

Common Stock Issued as Part of the Aera Merger

In connection with the Aera Merger, as described in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger,* on July 1, 2024 we entered into a registration rights agreement (Registration Rights Agreement) with the Sellers. In accordance with the Registration Rights Agreement, a total of 21,315,707 shares of common stock were registered pursuant to a registration statement on Form S-3 filed on August 5, 2024.

The Registration Rights Agreement contemplates that each Seller is subject to certain lock-up provisions whereby such Seller agreed not to transfer (1) any shares of common stock issued to such Seller to any non-affiliate until January 1, 2025; (2) more than one-third of the shares of common stock issued to such Seller to any non-affiliate until July 1, 2025; and (3) more than two-thirds of the shares of common stock issued to such Seller to any non-affiliate until January 1, 2026. The lock up provisions are subject to certain exceptions as more particularly described in the Registration Rights Agreement, included as an exhibit hereto.

Dividends

Dividends are payable to shareholders in quarterly increments, subject to the quarterly approval of our Board of Directors. The actual declaration of future cash dividends, and the establishment of record and payment dates, is subject to final determination by our Board of Directors each quarter after reviewing our financial performance.

On March 2, 2025, our Board of Directors declared a cash dividend of $0.3875 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 10, 2025 and is expected to be paid on March 21, 2025.

We paid the following cash dividends for each of the periods presented.

	Total Dividend	Annual Rate Per Share
	(in millions)	($ per share)
Year ended December 31, 2022	$ 59	$ 0.7925
Year ended December 31, 2023	81	$ 1.1575
Year ended December 31, 2024	113	$ 1.3950
	$ 253	

Share Repurchase Program

Our Board of Directors authorized a Share Repurchase Program to acquire up to $1.35 billion of our common stock through December 31, 2025. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. The following is a summary of our share repurchases, held as treasury stock, for the periods presented:

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2022	7,366,272	$ 313	$ 42.47
Year ended December 31, 2023	3,407,655	$ 143	$ 41.69
Year ended December 31, 2024	3,649,348	$ 192	$ 52.12
Inception of Program (May 2021) through December 31, 2024	18,513,263	$ 796	$ 42.82

Note: The total value of shares purchased includes approximately $2 million and $1 million in the years ended December 31, 2024 and 2023 related to excise taxes on share repurchases, which was effective beginning in 2023. Commissions paid were not significant in all periods presented.

Uses of Cash

2025 Capital Program

We expect our total 2025 capital program to range between $285 million and $335 million. Of this amount, $250 million to $280 million is related to our oil and natural gas segment, $20 million to $30 million is for our carbon management segment and $15 million to $25 million is for corporate and other activities. The above amounts related to carbon management projects do not include amounts funded by Brookfield through the Carbon TerraVault JV, such as drilling injection and monitoring wells at our 26R reservoir. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 4 Investments and Related Party Transactions* for more information on our joint venture with Brookfield.

Oil and natural gas segment – With respect to oil and natural gas development, we expect to run a one rig program in the first half of 2025 and add an additional rig in the second half of 2025. We expect our capital program related to oil and natural gas development to be focused on projects for which we have permits in hand. For more information on permitting, refer to *Part I, Item 1 and 2 – Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Carbon management segment – Our 2025 capital for carbon management projects includes approximately $16 million for the installation of carbon capture equipment at one of our gas processing facilities located at our Elk Hills field which we expect to be completed in 2025. This gas processing facility is adjacent to the 26R storage reservoir held by Carbon TerraVault JV. For more information this project, refer to *Part I, Item 1 and 2 – Business and Properties, Carbon Management Segment*.

Other Uses of Cash

Other than our 2025 capital program, our expected material uses of cash during 2025 include: (1) operating expenses; (2) dividends, share and debt repurchases; (3) settlements on commodity derivative contracts; (4) income taxes and other taxes not on income; (5) settlement of asset retirement obligations; and (6) costs related to advancing our carbon management activities not included in our capital program, such as employee costs and front-end engineering and design studies.

Our long-term material uses of cash include the following:

- repayment of principal and interest on our 2026 Senior Notes and 2029 Senior Notes (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt*)
- operating lease liabilities including our drilling rigs, commercial office space, fleet vehicles, easements and certain facilities (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 13 Leases)*
- obligations associated with our defined benefit and post-employment benefit plans (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 Pension and Postretirement Benefit Plans*)
- asset retirement obligations over the longer term (see *Part II, Item 8 – Financial Statements and Supplementary Data, Note 1 Nature of Business, Summary of Significant Accounting Policies and Other, Asset Retirement Obligations*)

We have certain off-balance sheet commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, oil and natural gas leases, obligations under long-term service agreements and field equipment. The table below summarizes our undiscounted current and long-term purchase obligations as of December 31, 2024.

	One Year or Less	More Than One Year	Total
		(in millions)	
Oil and gas leases, surface easements and pipeline right-of-way[(a)]	$ 1	$ 3	$ 4
Oil and gas transportation, throughput and storage arrangements[(b)]	16	37	53
Software licenses and other contracts	22	41	63
Contracts related to our carbon management segment[(c)]	—	77	77
Total	$ 39	$ 158	$ 197

(a) Oil and natural gas leases reflect obligations for fixed payments under our contracts.
(b) Purchase obligations for pipeline capacity include ship or pay arrangements that are based on contractual volumes and current market rates for firm transportation capacity during the contract period.
(c) Purchase obligation relates to solar power purchase agreements.

Cash Flow Analysis

Cash flows from operating activities – Our net cash provided by operating activities is sensitive to many variables, particularly changes in commodity prices. Commodity price movements may also lead to changes in other variables in our business, including adjustments to our capital program.

Our operating cash flow for the year ended December 31, 2024 was $610 million, which was a decrease of $43 million, from $653 million for the year ended December 31, 2023. The decrease was primarily driven by lower average realized prices, including natural gas prices in California markets. In total, our production increased on 2024 compared to 2023 after the completion of the Aera Merger on July 1, 2024. For the year ended December 31, 2024 we produced 110 MBoe/d, which was an increase of 24 MBoe/d from 86 MBoe/d for the year ended December 31, 2023. However, our natural gas production volume decreased by 18 MMcf per day, from 135 MMcf/d during the year ended December 31, 2023 to 117 MMcf/d in the year ended December 31, 2024 predominantly as a result of scheduled maintenance and unplanned down time at our Elk Hills power plant as well as natural decline. Additionally, average realized price for natural gas decreased by $5.60 per Mcf from $8.59 Mcf for the year ended December 31, 2023 to $2.99 Mcf for the year ended December 31, 2024. Our average realized price for oil without the effects of derivative settlements decreased by $3.49 to $76.92 for the year ended December 31, 2024 compared to $80.41 for the same prior year period. We also earned a lower margin on our marketing activities in 2024 as compared to the same prior year period. For more information on our production and price changes, see *Segment Results of Oil and Natural Gas Operations* above.

Settlement payments from our oil derivative contracts decreased $208 million from $272 million for the year ended December 31, 2023 to $64 million for the year ended December 31, 2024. Shortly after emergence from bankruptcy in 2020, we entered into derivative positions through September 2023 to meet the requirements of our Revolving Credit Facility. At that time we entered into commodity derivative contracts during a low commodity price environment. In addition to these bankruptcy-related contracts being settled in the year ended December 31, 2023, the percentage of our production that we were required to hedge was lower in the year ended December 31, 2024 as compared to the same prior year period.

During 2024, primarily due to acquired natural gas derivative contracts in the Aera Merger, we paid higher settlements on related commodity price protection on purchased natural gas. For the year ended December 31, 2024, we made settlement payments of $32 million. We had no settlement payments on derivative contracts related to purchased natural gas derivatives during the year ended December 31, 2023. For more information on our existing hedges see, *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives.*

Operating costs and general and administrative expenses increased in 2024 as compared to 2023 primarily due to the addition of Aera's operations on July 1, 2024. As a result, we had higher compensation-related costs and additional costs related to downhole maintenance activity, surface maintenance and purchase injectant. Excluding the Aera Merger, we realized cost savings related to strategic initiatives we implemented in the second half of 2023.

Cash flows from investing activities – The table below summarizes net cash used in investing activities:

	Year ended December 31,	
	2024	2023
	(in millions)	
Capital investments[a]	$ (255)	$ (185)
Changes in capital accruals	29	(13)
Proceeds from divestitures	15	32
Purchase of a business, net of cash acquired	(853)	—
Acquisitions	(6)	(5)
Other	(7)	(4)
Net cash used in investing activities	$ (1,077)	$ (175)

(a) Includes capital investments of $234 million in our oil and natural gas segment and $12 million in our carbon management segment in 2024. Includes capital investments of $153 million in our oil and natural gas segment and $5 million in our carbon management segment in 2023.

The increase in cash used in investing activities primarily relates to the Aera Merger which closed on July 1, 2024. As a result of the Aera Merger, we also increased our capital program in 2024 compared to 2023. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger* for more information on the transaction.

Proceeds from asset divestitures for the year ended December 31, 2024 primarily included the sale of our 0.9-acre Fort Apache real estate property in Huntington Beach, California as well as the remaining portion of our Ventura assets which were classified as held for sale. Proceeds from asset divestitures for the year ended December 31, 2023 included the sale of our non-operated interest in the Round Mountain Unit. In each of the years ended December 31, 2024 and 2023, the acquisitions shown in the table above related to purchasing storage reservoirs for our carbon management segment. *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* for more information on our divestitures and acquisitions.

Cash flows from financing activities – The table below summarizes net cash used by financing activities:

	Year ended December 31,	
	2024	2023
	(in millions)	
Proceeds from Revolving Credit Facility	$ 30	$ —
Repayments of Revolving Credit Facility	(30)	—
Proceeds from 2029 Senior Notes, net	888	—
Repurchases of common stock[a]	(192)	(143)
Common stock dividends	(113)	(81)
Payments on equity-settled awards	(4)	—
Issuance of common stock	2	2
Bridge loan commitments	(5)	—
Debt repurchases	(303)	(56)
Debt amendment costs	(18)	(8)
Stock warrants exercised	130	—
Shares cancelled for taxes	(42)	(3)
Net cash used by financing activities	$ 343	$ (289)

(a) The total value of shares purchased reported on our statement of cash flows includes approximately $2 million and $1 million in the years ended December 31, 2024 and 2023, respectively, related to excise taxes on share repurchases, which was effective beginning on January 1, 2023. Commissions paid on share repurchases were not significant in all periods presented.

As noted above in *Long-Term Debt*, we completed an initial offering and a follow-on offering for our 2029 Senior Notes. In conjunction, we also repurchased $300 million face value of our 2026 Senior Notes. In the year ended December 31, 2023, we repurchased $55 million in face value of our 2026 Senior Notes. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 5 Debt* for more information on our financing arrangements.

Cash used for repurchases of our common stock under our Share Repurchase Program increased in 2024 as compared to 2023. Additionally, our Board of Directors increased the quarterly dividend rate on our common stock during 2024. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 11 Stockholders' Equity* for more information on our Share Repurchase Program and cash dividends.

A significant number of stock-based compensation awards were settled in the first quarter of 2024. These awards were primarily granted in January 2021 following our emergence from bankruptcy. We withheld shares of common stock to satisfy the tax withholding obligations (shares cancelled for taxes). In addition to the $113 million of dividends paid in the year ended December 31, 2024, we paid $4 million of dividend equivalents accrued on our stock-based compensation awards. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 10 Stock-Based Compensation* for more information on equity awards.

Divestitures and Acquisitions

From time to time, we review our extensive portfolio of assets for potential divestitures. See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 9 Divestitures and Acquisitions* and *Note 19 Subsequent Events* for more information on our transactions.

Seasonality

Certain of our operating costs and the prices for our products fluctuate throughout the year. For example, prices for natural gas (that we both market to third parties and purchase for use in our operations) tend to be higher in the winter and summer months. However, seasonality overall does not have a material effect on our earnings during the year.

Lawsuits, Claims, Commitments and Contingencies

We are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2024 and 2023 were not material to our consolidated balance sheets as of such dates.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE's order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and we are challenging the order from BSEE. In March 2024, we entered into a cost sharing agreement with former lessees to share in ongoing maintenance costs during the pendency of the challenge to the BSEE order. We estimate our ongoing share of maintenance costs for the platforms could be approximately $5 million per year. Due to the preliminary stage of the process, no cost estimates to abandon the offshore platforms have been determined.

We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

See *Part II, Item 8 – Financial Statements and Supplementary Data, Note 6 Lawsuits, Claims, Commitments and Contingencies*.

Critical Accounting Estimates

Our critical accounting estimates that could result in a material impact to the consolidated financial statements due to the levels of subjectivity and management judgment include the following:

Title	Description	Estimation and Uncertainties	Sensitivities
Oil and Natural Gas Properties	The carrying value of our property, plant and equipment represents the costs incurred to acquire or develop the asset, including any asset retirement obligations, net of accumulated depreciation, depletion and amortization. For assets acquired in a business combination, PP&E cost is based on fair values at the acquisition date. We use the successful efforts method of accounting for our oil and natural gas producing activities. Under this method, we capitalize the cost of acquiring properties, development costs and the costs of drilling successful exploration wells. The estimated amount of proved reserve volumes is used as the basis for recording depletion expense. We determine depletion on our oil and natural gas producing properties using the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are depleted based on proved developed oil and natural gas reserves. Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price	The determination of quantities of proved reserves is a highly technical process performed by our engineers and geoscientists. The analysis is based on drilling results, reservoir performance, subsurface interpretation and future development plans. Production rate forecasts are primarily derived from estimates from decline-curve analysis and type-curve analysis. Secondary inputs may include material balance calculations, which consider the volumes of substances replacing the volumes produced and associated reservoir pressure changes. Additional inputs may also include seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continuous reassessment of the viability of future production volumes under varying economic conditions. Several other factors could change our proved oil and gas reserves including changes in energy costs, inflation, deflation and the political and	Our total proved reserves were 545 MMBoe and our total proved developed reserves were 506 MMBoe at December 31, 2024. We estimate our 2025 depletion rate for oil and natural gas producing properties using the unit-of-production method will be approximately $10/Boe. A 5% change in our reserves would increase or decrease this DD&A rate by approximately $0.51/Boe.

Title	Description	Estimation and Uncertainties	Sensitivities
	over the amounts assigned to assets and liabilities is recorded as goodwill. The preliminary fair value of Aera's proved reserves acquired in the acquisition approximate $3 billion. We do not have significant capitalized costs related to unproved properties and have not identified significant unproved properties as a result of the acquisition of Aera.	regulatory environment, all of which are beyond our control. We estimated the fair value of Aera's proved reserves at the acquisition date using the expected present value of discounted future cash flows, on an after-tax basis, and applying a reasonable discount rate. We have used all available information to make a fair value determination, including assistance from third-party valuation experts. The assumptions used are believed to be reasonable but could change. This would have the effect of increasing or decreasing the amount of DD&A we recognized on acquired assets.	
Asset Retirement Obligations	Our asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells and facilities used in oil and natural gas segment. We determine our asset retirement obligation, including the obligations related to Aera's assets we acquired, by calculating the present value of estimated future cash outflows related to the abandonment obligation. The asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset or included in the fair value estimate in a business combination. In periods subsequent to initial measurement, the asset retirement cost is depreciated using the unit-of-production method, while increases in the ARO liability resulting from the passage of time (accretion expense) is included in operating expenses on our consolidated statements of operations.	The recognition of an asset retirement obligation requires us to make assumptions including an estimate of future abandonment costs and inflation rates, timing of activity and our credit-adjusted discount rate among others. Changes in the legal, regulatory and political environment could also affect our estimated future cash outflows.	As of December 31, 2024 and 2023, we had asset retirement obligations of $1,129 million and $521 million, respectively. A 1% increase in the inflation rate would increase our liability by $97 million and a 1% decrease in the inflation rate would decrease our liability by $91 million as of December 31, 2024.

FORWARD-LOOKING STATEMENTS

This document contains statements that we believe to be “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts are forward-looking statements, and include statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and plans and objectives of management for the future. Words such as “expect,” “could,” “may,” “anticipate,” “intend,” “plan,” “ability,” “believe,” “seek,” “see,” “will,” “would,” “estimate,” “forecast,” “target,” “guidance,” “outlook,” “opportunity” or “strategy” or similar expressions are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Additionally, the information in this report contains forward-looking statements related to the recently announced Aera merger.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- fluctuations in commodity prices, including supply and demand considerations for our products and services, and the impact of such fluctuations on revenues and operating expenses;
- decisions as to production levels and/or pricing by OPEC or U.S. producers in future periods;
- government policy, war and political conditions and events, including the military conflicts in Israel, Lebanon, Ukraine and the Middle East;
- the ability to successfully execute integration efforts in connection with the Aera Merger, and achieve projected synergies and ensure that such synergies are sustainable;
- regulatory actions and changes that affect the oil and gas industry generally and us in particular, including (1) the availability or timing of, or conditions imposed on, EPA and other governmental permits and approvals necessary for drilling or development activities or our carbon management segment; (2) the management of energy, water, land, greenhouse gases (GHGs) or other emissions, (3) the protection of health, safety and the environment, or (4) the transportation, marketing and sale of our products;
- the efforts of activists to delay prevent oil and gas activities or the development of our carbon management segment through a variety of tactics, including litigation;
- the impact of inflation on future expenses and changes generally in the prices of goods and services;
- changes in business strategy and our capital plan;
- lower-than-expected production or higher-than-expected production decline rates;
- changes to our estimates of reserves and related future cash flows, including changes arising from our inability to develop such reserves in a timely manner, and any inability to replace such reserves;
- the recoverability of resources and unexpected geologic conditions;
- general economic conditions and trends, including conditions in the worldwide financial, trade and credit markets;
- production-sharing contracts’ effects on production and operating costs;
- the lack of available equipment, service or labor price inflation;

- limitations on transportation or storage capacity and the need to shut-in wells;
- any failure of risk management;
- results from operations and competition in the industries in which we operate;
- our ability to realize the anticipated benefits from prior or future efforts to reduce costs;
- environmental risks and liability under federal, regional, state, provincial, tribal, local and international environmental laws and regulations (including remedial actions);
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, CCS project participants and other parties;
- reorganization or restructuring of our operations;
- our ability to claim and utilize tax credits or other incentives in connection with our CCS projects;
- our ability to realize the benefits contemplated by our energy transition strategies and initiatives, including CCS projects and other renewable energy efforts;
- our ability to successfully identify, develop and finance carbon capture and storage projects and other renewable energy efforts, including those in connection with the Carbon TerraVault JV, and our ability to convert our CDMAs to definitive agreements and enter into other offtake agreements;
- our ability to maximize the value of our carbon management segment and operate it on a stand alone basis;
- our ability to successfully develop infrastructure projects and enter into third party contracts on contemplated terms;
- uncertainty around the accounting of emissions and our ability to successfully gather and verify emissions data and other environmental impacts;
- changes to our dividend policy and share repurchase program, and our ability to declare future dividends or repurchase shares under our debt agreements;
- limitations on our financial flexibility due to existing and future debt;
- insufficient cash flow to fund our capital plan and other planned investments and return capital to shareholders;
- changes in interest rates;
- our access to and the terms of credit in commercial banking and capital markets, including our ability to refinance our debt or obtain separate financing for our carbon management segment;
- changes in state, federal or international tax rates, including our ability to utilize our net operating loss carryforwards to reduce our income tax obligations;
- effects of hedging transactions;
- the effect of our stock price on costs associated with incentive compensation;
- inability to enter into desirable transactions, including joint ventures, divestitures of oil and natural gas properties and real estate, and acquisitions, and our ability to achieve any expected synergies;
- disruptions due to earthquakes, forest fires, floods, extreme weather events or other natural occurrences, accidents, mechanical failures, power outages, transportation or storage constraints, labor difficulties, cybersecurity breaches or attacks or other catastrophic events;
- pandemics, epidemics, outbreaks, or other public health events, such as the COVID-19 pandemic; and
- other factors discussed in *Part I, Item 1A – Risk Factors.*

We caution you not to place undue reliance on forward-looking statements contained in this document, which speak only as of the filing date, and we undertake no obligation to update this information. This document may also contain information from third party sources. This data may involve a number of assumptions and limitations, and we have not independently verified them and do not warrant the accuracy or completeness of such third-party information.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our financial results are sensitive to fluctuations in oil, NGL and natural gas prices. These commodity price changes also impact the volume changes under PSCs. We maintain a commodity hedging program focused on crude oil and natural gas to help protect our cash flows, margins and capital program from the volatility of crude oil and natural gas prices. We have not designated any instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. We believe we have limited price volatility risk in the near term as a result of our current hedges in place. As of December 31, 2024, we had hedges on approximately 70% of our anticipated oil production through 2025 and approximately 45% through 2026.

The primary market risk relating to our derivative contracts relates to fluctuations in market prices as compared to the fixed contract price for a notional amount of our production. As of December 31, 2024, we had net assets of $65 million for our derivative commodity positions which are carried at fair value, using industry-standard models with various inputs, including the forward curve for the relevant price index. We estimate that a $10/bbl increase in Brent oil forward prices could increase our settlement payments by $170 million in 2025, limiting our upside. We estimate that a $10 decrease in Brent oil forward prices could decrease our settlement payments by $178 million in 2025, negating the downside price movement for hedged volumes.

A summary of our Brent-based crude oil derivative contracts at December 31, 2024 are included in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 7 Derivatives*.

Counterparty Credit Risk

Our counterparty credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each counterparty is monitored for outstanding balances and current activity. Counterparty credit limits have been established based upon the financial health of counterparties, and these limits are actively monitored. In the event counterparty credit risk is heightened, we may request collateral or accelerate payment dates for product deliveries. Approximately 73% of our production during 2024 was oil which was sold predominately to refineries in California. Trade receivables for all commodities are collected within 30 to 60 days following the month of delivery. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We have master netting agreements with each of our derivative counterparties, which allow us to net our settlement payments for the same commodity with the same counterparty. Therefore, our loss is limited to the net amount due from a defaulting counterparty. The majority of our credit exposure was with investment grade counterparties. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

Interest-Rate Risk

We had no variable-rate debt outstanding as of December 31, 2024.

Other Competition Risk

We face competition in our oil and natural gas segment from other sources of energy, including wind and solar power. These products compete directly with the electricity we generate from our Elk Hills power plant and indirectly as substitutes for oil, natural gas and NGLs. We expect competition from these sources to intensify in the future due to technological advances and as California may continue to develop renewable energy and implement climate-related policies.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
California Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2024 and December 31, 2023, the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2024, and the related notes and financial statement schedule II (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and December 31, 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2024, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company acquired Aera Energy, LLC during 2024, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2024, Aera Energy, LLC's internal control over financial reporting associated with 45% of total assets and 38% of total revenues included in the consolidated financial statements of the Company as of and for the year ended December 31, 2024. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Aera Energy, LLC.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 Management's Annual Assessment of and Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the 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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated 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 consolidated 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 a separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of estimated oil and gas reserves on depletion expense for proved oil and gas properties

As discussed in Note 1 to the consolidated financial statements, the Company determines depletion of oil and gas producing properties by the unit-of-production method. Under this method, acquisition costs are amortized based on total proved oil and gas reserves and capitalized development and successful exploration costs are amortized based on proved developed oil and gas reserves. The Company recorded depreciation, depletion, and amortization expense of $388 million for the year ended December 31, 2024. Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration estimates of future production, operating and development costs and commodity prices inclusive of market differentials. The Company employs technical personnel, such as reservoir engineers and geoscientists, who estimate proved oil and gas reserves. The Company also engages independent reservoir engineering specialists to perform an independent evaluation of the Company's proved oil and gas reserves estimates.

We identified the assessment of estimated proved oil and gas reserves on the determination of depreciation, depletion and amortization expense for proved oil and gas properties as a critical audit matter. Complex auditor judgment was required to evaluate the Company's estimate of proved oil and gas reserves, which is an input to the determination of depreciation, depletion, and amortization expense. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to estimated future oil and gas production, future commodity prices inclusive of market differentials, and future operating and development costs.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's depletion process, including controls related to the estimation of proved oil and gas reserves. We evaluated (1) the professional qualifications of the Company's internal reserve engineers, as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Company's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm to the Company. We assessed the methodology used by the technical personnel employed by the Company and the independent reservoir engineering specialist to estimate the reserves used in the determination of depreciation, depletion and amortization expense for compliance with industry and regulatory standards. We compared estimated future oil and gas production and estimated future operating and development costs estimated by the technical personnel employed by the Company to historical results. We compared the commodity prices used by the Company's internal technical personnel to publicly available prices and recalculated the relevant market differentials based on actual price realizations. We read and considered the reports of the independent reservoir engineering specialist in connect with our evaluation of the Company's proved oil and gas reserves estimates.

Evaluation of the fair value measurement of oil and gas properties acquired in the Aera Energy LLC business combination

As discussed in Note 2 to the consolidated financial statements, on July 1, 2024, the Company completed a merger with Aera Energy, LLC (Aera) for cash and equity consideration of approximately $2.1 billion. The transaction was accounted for as a business combination using the acquisition method, with the Company being identified as the accounting acquirer. Under the acquisition method of accounting the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. As a result of the transaction, the Company acquired proved oil and gas properties which were recognized at their acquisition date fair value of $2.9 billion.

We identified the evaluation of the initial fair value measurement of the oil and gas properties acquired in the Aera transaction as a critical audit matter. Subjective auditor judgment was required in evaluating the key assumptions used to estimate the fair value of the proved oil and gas properties as changes to those assumptions could have had a significant effect on the fair value. The key assumptions used by the Company to determine fair value included forecasted commodity prices, reserve category risk adjustment factors, estimated future oil and gas production, estimated future operating and capital costs and discount rate. Additionally, the audit effort associated with evaluating the forecasted commodity prices, reserve category risk adjustment factors, and discount rate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's acquisition-date valuation process, including controls related to the determination of the key assumptions, as noted above, used to measure the initial fair value of the acquired proved oil and gas properties. We evaluated the professional qualifications of the Company's internal reservoir engineers and their knowledge, skills, and ability relative to the valuation process. We evaluated the process and assessed the methodology used by the Company's internal reservoir engineers to estimate the proved future production volumes for compliance with industry and regulatory standards. We compared the estimated future proved oil and gas production and estimated future operating and capital costs determined by the technical personnel employed by the Company to historical Aera production volumes and historical costs. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in: 1) evaluating the Company's discount rate by comparing it to a discount rate range that was independently developed using publicly available market data for comparable entities, 2) evaluating the reserve category risk adjustment factors used by the Company by comparing them to third party publications of risk adjustment factors utilized by market participants, 3) evaluating the forecasted commodity price assumption by comparing it to an independently developed range of forward price estimates using data from analysts and other industry sources, 4) evaluating the projected inflation rate by comparing it to an inflation rate range that was independently developed using publicly available data.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Los Angeles, California
March 3, 2025

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2024 and 2023
(in millions, except share data)

	2024	2023
CURRENT ASSETS		
Cash and cash equivalents	$ 372	$ 496
Trade receivables	330	216
Inventories	90	72
Assets held for sale	10	13
Receivables from affiliate	46	19
Other current assets, net	176	113
Total current assets	1,024	929
PROPERTY, PLANT AND EQUIPMENT	6,738	3,437
Accumulated depreciation, depletion and amortization	(1,058)	(667)
Total property, plant and equipment, net	5,680	2,770
INVESTMENT IN UNCONSOLIDATED SUBSIDIARIES	86	19
DEFERRED TAX ASSETS	73	132
OTHER NONCURRENT ASSETS	272	148
TOTAL ASSETS	$ 7,135	$ 3,998
CURRENT LIABILITIES		
Accounts payable	369	245
Liabilities associated with assets held for sale	—	5
Accrued liabilities	611	366
Total current liabilities	980	616
NONCURRENT LIABILITIES		
Long-term debt, net	1,132	540
Asset retirement obligations	995	422
Deferred tax liabilities	113	—
Other long-term liabilities	377	201
STOCKHOLDERS' EQUITY		
Preferred stock (20,000,000 shares authorized at $0.01 par value); no shares outstanding at December 31, 2024 or 2023	—	—
Common stock (200,000,000 shares authorized at $0.01 par value); (109,613,585 and 83,557,800 shares issued; 91,100,322 and 68,693,885 shares outstanding at December 31, 2024 and 2023, respectively)	1	1
Treasury stock (18,513,263 shares held at cost at December 31, 2024 and 14,863,915 shares held at December 31, 2023)	(796)	(604)
Additional paid-in capital	2,578	1,329
Retained earnings	1,680	1,419
Accumulated other comprehensive income	75	74
Total stockholders' equity	3,538	2,219
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 7,135	$ 3,998

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2024, 2023 and 2022
(in millions, except per share data)

	Year ended December 31,		
	2024	2023	2022
REVENUES			
Oil, natural gas and NGL sales	$ 2,537	$ 2,155	$ 2,643
Net gain (loss) from commodity derivatives	241	(12)	(551)
Revenue from marketing of purchased commodities	235	407	331
Electricity sales	159	211	261
Interest and other revenue	26	40	23
Total operating revenues	3,198	2,801	2,707
OPERATING EXPENSES			
Operating costs	966	822	785
General and administrative expenses	321	267	222
Depreciation, depletion and amortization	388	225	198
Asset impairment	14	3	2
Taxes other than on income	242	165	162
Costs related to marketing of purchased commodities	193	224	285
Electricity generation expenses	40	103	167
Transportation costs	81	67	50
Accretion expense	87	46	43
Net loss on natural gas purchase derivatives	30	8	—
Carbon management business expenses	56	37	14
Measurement period adjustments	(12)	—	—
Other operating expenses, net	183	58	26
Total operating expenses	2,589	2,025	1,954
Net gain on asset divestitures	11	32	59
OPERATING INCOME	620	808	812
NON-OPERATING (EXPENSES) INCOME			
Interest and debt expense	(87)	(56)	(53)
Loss on early extinguishment of debt	(5)	(1)	—
Loss from investment in unconsolidated subsidiaries	(10)	(9)	(1)
Other non-operating (loss) income	(2)	6	3
INCOME BEFORE INCOME TAXES	516	748	761
Income tax provision	(140)	(184)	(237)
NET INCOME	$ 376	$ 564	$ 524
Net income attributable to common stock per share			
Basic	$ 4.74	$ 8.10	$ 6.94
Diluted	$ 4.62	$ 7.78	$ 6.75
Weighted-average common shares outstanding			
Basic	79.3	69.6	75.5
Diluted	81.4	72.5	77.6

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income (Loss)
For the years ended December 31, 2024, 2023 and 2022
(in millions)

	Year ended December 31,		
	2024	2023	2022
Net income	$ 376	$ 564	$ 524
Other comprehensive income (loss)[a]:			
Actuarial gain (loss) associated with pension and postretirement plans	3	(1)	13
Prior service credit	2	—	—
Recognition of prior service credit due to curtailment	—	(2)	—
Recognition of net actuarial gain due to curtailment	(3)	—	—
Recognition of net actuarial loss due to special termination benefits	3	—	—
Amortization of prior service cost credit included in net periodic benefit cost, net of tax	(4)	(4)	(4)
Total other comprehensive income (loss)	1	(7)	9
Comprehensive income	$ 377	$ 557	$ 533

(a) Amounts are net of a tax provision of $1 million, tax benefit of $3 million, and tax provision of $4 million in tax for the years ended December 31, 2024, 2023, and 2022, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders' Equity (Deficit)
For the years ended December 31, 2024, 2023 and 2022
(in millions)

	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
Balance, December 31, 2021	$ 1	$ (148)	$ 1,288	$ 475	$ 72	$ 1,688
Net income	—	—	—	524	—	524
Share-based compensation	—	—	19	—	—	19
Repurchases of common stock	—	(313)	—	—	—	(313)
Cash dividends ($0.7925 per share)	—	—	—	(61)	—	(61)
Other comprehensive income, net of tax	—	—	—	—	9	9
Other	—	—	(2)	—	—	(2)
Balance, December 31, 2022	$ 1	$ (461)	$ 1,305	$ 938	$ 81	$ 1,864
Net income	—	—	—	564	—	564
Share-based compensation	—	—	28	—	—	28
Repurchases of common stock	—	(143)	—	—	—	(143)
Cash dividends ($1.1575 per share)	—	—	—	(83)	—	(83)
Shares cancelled for taxes	—	—	(3)	—	—	(3)
Other comprehensive income, net of tax	—	—	—	—	(7)	(7)
Other	—	—	(1)	—	—	(1)
Balance, December 31, 2023	$ 1	$ (604)	$ 1,329	$ 1,419	$ 74	$ 2,219
Net income	—	—	—	376	—	376
Share-based compensation	—	—	25	—	—	25
Repurchases of common stock	—	(192)	—	—	—	(192)
Shares issued for warrants	—	—	130	—	—	130
Shares issued for Aera Merger	—	—	1,136	—	—	1,136
Cash dividends ($1.3950 per share)	—	—	—	(115)	—	(115)
Shares cancelled for taxes	—	—	(42)	—	—	(42)
Other comprehensive income, net of tax	—	—	—	—	1	1
Balance, December 31, 2024	$ 1	$ (796)	$ 2,578	$ 1,680	$ 75	$ 3,538

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2024, 2023 and 2022
(in millions)

	Year ended December 31,		
	2024	2023	2022
CASH FLOW FROM OPERATING ACTIVITIES			
Net income	$ 376	$ 564	$ 524
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	388	225	198
Deferred income tax provision	71	35	226
Asset impairments	14	3	2
Net (gain) loss from commodity derivatives	(211)	20	551
Settlement payments from commodity derivatives	(64)	(272)	(738)
Loss on early extinguishment of debt	5	1	—
Net gain on asset divestitures	(11)	(32)	(59)
Other non-cash charges to income, net	139	103	43
Changes in operating assets and liabilities, net:			
Decrease (increase) in trade receivables	58	110	(81)
(Increase) in inventories	(1)	(12)	—
Decrease in other current assets, net	28	—	35
Decrease in accounts payable and accrued liabilities	(182)	(92)	(11)
Net cash provided by operating activities	610	653	690
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(255)	(185)	(379)
Changes in accrued capital investments	29	(13)	1
Proceeds from asset divestitures	15	32	80
Purchase of a business, net of cash acquired	(853)	—	—
Acquisitions	(6)	(5)	(17)
Distribution related to the Carbon TerraVault JV	—	—	12
Capitalized joint venture transaction costs	—	—	(12)
Other	(7)	(4)	(2)
Net cash used in investing activities	(1,077)	(175)	(317)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from Revolving Credit Facility	30	—	—
Repayments of Revolving Credit Facility	(30)	—	—
Proceeds from 2029 Senior Notes, net	888	—	—
Debt repurchases	(303)	(56)	—
Debt amendment costs	(18)	(8)	—
Repurchases of common stock	(192)	(143)	(313)
Common stock dividends	(113)	(81)	(59)
Payments on equity-settled awards	(4)	—	—
Issuance of common stock	2	2	1
Bridge loan commitments	(5)	—	—
Stock warrants exercised	130	—	—
Shares cancelled for taxes	(42)	(3)	—
Net cash provided by (used in) financing activities	343	(289)	(371)
(Decrease) increase in cash	(124)	189	2
Cash and cash equivalents—beginning of period	496	307	305
Cash and cash equivalents—end of period	$ 372	$ 496	$ 307

The accompanying notes are an integral part of these consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

NOTE 1 NATURE OF BUSINESS, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

Nature of Business

We are an independent energy and carbon management company committed to energy transition. We are committed to environmental stewardship while safely providing local, responsibly sourced energy. We are also focused on maximizing the value of our land, mineral ownership, and energy expertise for decarbonization by developing carbon capture and storage (CCS) and other emissions-reducing projects.

Our reportable segments include oil and natural gas and carbon management. The oil and gas segment explores for, develops, and produces oil and condensate, natural gas liquids and natural gas. The carbon management segment, which we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and storage facilities. Our carbon management segment includes our investment in the Carbon TerraVault joint venture. See *Note 4 Investments and Related Party Transactions* and *Note 16 Segment Information* for additional information.

On July 1, 2024, pursuant to the Agreement and Plan of Merger, dated as of February 7, 2024 (the Merger Agreement), we acquired Aera Energy LLC (Aera) in an all-stock transaction (Aera Merger). See *Note 2 Aera Merger* for transaction details. The effective date of the acquisition was January 1, 2024.

Except when the context otherwise requires or where otherwise indicated, all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its consolidated subsidiaries as of the date presented.

Basis of Presentation

We have prepared this report in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and the rules and regulations of the U.S. Securities and Exchange Commission applicable to annual financial information.

All financial information presented consists of our consolidated results of operations, financial position and cash flows. We have eliminated intercompany transactions and balances. We account for our share of oil and natural gas producing activities, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our consolidated financial statements. We have conformed Aera's accounting policies to our legacy methods for all significant balances included in our consolidated financial statements. Our consolidated results of operations include the results of Aera beginning July 1, 2024, the closing date of the Aera Merger. The Aera Merger and related transactions have significantly impacted the comparability of our financial results for 2024 and prior years. In applying the equity method of accounting, our investments in our unconsolidated subsidiaries are recognized either at cost, as is the case with Carbon TerraVault JV HoldCo, LLC, or at fair value if acquired in a business combination, as is the case for Midway Sunset Cogeneration Company. These investments are then adjusted for our proportionate share of income or loss in addition to contributions and distributions.

Certain prior period balances related to natural gas liquid (NGL) marketing activities were reclassified to conform to our 2024 presentation. For the years ended December 31, 2023 and 2022, we reclassified $6 million and $17 million, respectively, related to NGL storage activities from other revenue to revenue from marketing of purchased commodities on our consolidated statements of operations. For the years ended December 31, 2023 and 2022, we reclassified $3 million and $12 million, respectively, related to NGL processing fees from other operating expenses, net to costs related to marketing of purchased commodities on our consolidated statements of operations.

Use of Estimates

The process of preparing financial statements in conformity with U.S. GAAP requires management to select appropriate accounting policies and make informed estimates and judgments regarding certain types of financial statement balances and disclosures. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements and judgments on expected outcomes as well as the materiality of transactions and balances. Changes in facts and circumstances or discovery of new information relating to such transactions and events may result in revised estimates and judgments. Further, actual results may differ from estimates upon settlement. Management believes that these estimates and judgments provide a reasonable basis for the fair presentation of our consolidated financial statements.

Risks and Uncertainties

Our revenue, profitability and future growth of our oil and natural gas segment are substantially dependent upon prevailing and future prices for the commodities we produce and sell, which can be volatile and fluctuate significantly due to factors beyond our control, including our ability to obtain permits. We are in the early stages of developing a carbon capture and sequestration business which is subject to risks as an emerging industry and availability of tax incentives. We operate exclusively in California which is a highly regulated environment.

Concentration of Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other customers that have access to transportation and storage facilities. In light of the ongoing energy deficit in California and strong demand for native crude oil production, we do not believe that the loss of any single customer would have a material adverse effect on our consolidated financial statements taken as a whole.

For the year ended December 31, 2024, four customers of our oil and gas segment each accounted for at least 10%, and collectively 67%, of our sales (before the effects of hedging). For the year ended December 31, 2023, three customers of our oil and gas segment each accounted for at least 10%, and collectively 44%, of our sales (before the effects of hedging). For the year ended December 31, 2022, three customers of our oil and gas segment each accounted for at least 10%, and collectively accounted for 52%, of our sales (before the effects of hedging).

Recently Adopted Accounting and Disclosure Changes

In November 2023, the Financial Accounting Standards Board's (FASB) issued improvements to the segment disclosure requirements primarily to enhance disclosure of significant segment expenses. The new disclosure requirements are applied retrospectively to all prior periods included in the financial statements. We adopted these new rules for the year ended December 31, 2024 adding *Note 16 Segment Information*.

In December 2023, the FASB issued improvements to the disclosure requirements for *Income Taxes* (ASC 740). The new disclosure requirements are to be applied on a prospective basis, but a retrospective application is permitted. We early adopted these rules for the year ended December 31, 2024, retrospectively presenting our income tax disclosures, as shown in *Note 8 Income Taxes*.

Recently Issued but not Adopted Accounting and Disclosure Changes

In November 2024, the FASB issued new disclosure requirements to enhance disclosure of certain costs and expenses. These new expense disclosures will apply to us. The rules are effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027, early adoption is permitted. We expect that the adoption of these rules will only impact our disclosures and have no impact to our results of operations, cash flows and financial condition.

Accounting Policies

Fair Value Measurements

Our assets and liabilities measured at fair value are categorized in a three-level fair-value hierarchy, based on the inputs to the valuation techniques:

Level 1—using quoted prices in active markets for the assets or liabilities;
Level 2—using observable inputs other than quoted prices for the assets or liabilities; and
Level 3—using unobservable inputs.

Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows and discount rates.

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. Our commodity derivatives comprise of over-the-counter bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices based on transactions executed in the marketplace. We classify these measurements as Level 2.

Our PP&E may be written down to fair value if we determine that there has been an impairment. The fair value is determined as of the date of the assessment generally using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves, inclusive of market differentials, as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate.

The carrying amounts of cash and other on-balance sheet financial instruments, other than fixed-rate debt, approximate fair value. See *Note 5 Debt* for the fair value of our fixed-rate debt.

We may enter into joint ventures that are considered to be a variable interest entity (VIE). A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. We consolidate a VIE if we determine that we have (i) the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) the obligation to absorb losses or the right to receive benefits from the VIE that are more than insignificant to the VIE. If an entity is determined to be a VIE but we do not have a controlling interest, the entity is accounted for under either the cost or equity method depending on whether we exercise significant influence. See Note 4 Investments and Related Party Transactions for more information on the Carbon TerraVault JV.

We also may enter into investments in entities that are considered to be voting interest entities (VOEs). A VOE is a legal entity that does not meet the conditions of a VIE as outlined above. We consolidate a VOE if we determine that we have a controlling financial interest in the VOE. If an entity is determined to be a VOE but we do not have a controlling financial interest, the entity is accounted for under either the cost or equity method, depending on the structure of the entity. See *Note 4 Investments and Related Party Transactions* for more information on our investment in the Midway Sunset Cogeneration Company.

These evaluations are highly complex and involve management judgment and may involve the use of estimates and assumptions based on available information. The evaluation requires continual assessment. Investments in unconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred, which is other than temporary.

Business Combinations

We account for business combination in accordance with Accounting Standards Codification Topic 805, *Business Combinations* (ASC 805). Under the acquisition method of accounting in ASC 805, the assets acquired and liabilities assumed are measured as of their acquisition date fair value. Fair value is the price that we estimate would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Accounting for business combinations requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill. If the fair value of the assets acquired and the liabilities assumed are greater than the purchase price, then a bargain purchase gain is recognized. Transaction and integration costs associated with business combinations are expensed as incurred.

Revenue Recognition

We derive substantially all of our revenue from sales of oil, natural gas and NGLs, with the remaining revenue generated from sales of electricity and marketing activities related to storage and managing excess pipeline capacity. Revenues are recognized when control of promised goods is transferred to our customers, in an amount that reflects the consideration we expect to receive in exchange for those goods. See *Note 15 Revenue* for more information on our revenue from contracts with customers.

Restricted Cash

Restricted cash of $18 million, included in cash and cash equivalents on our consolidated balance sheet, at December 31, 2024 primarily includes funds held in an escrow account established to secure well and infrastructure abandonment and habitat restoration at an oil and gas field previously owned by Aera. Refer to Note 2 Aera Merger for more information. Funds will be released from the escrow account as work is completed. The Merger Agreement provides that 50% of the amount of released funds exceeds the cumulative abandonment and habitat restoration expenditures from January 1, 2024 onward is payable to the prior owners of Aera (Sellers). We do not expect this return of excess cash to be significant. We had no restricted cash at December 31, 2023.

Inventories

Materials and supplies, which primarily consist of well equipment and tubular goods used in oil and natural gas operations, are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods are predominantly comprised of oil and natural gas liquids (NGLs), which are valued at the lower of cost or net realizable value. Inventories, by category, are as follows:

	2024	2023
	(in millions)	
Materials and supplies	$ 86	$ 68
Finished goods	4	4
Total	$ 90	$ 72

In the year ended December 31, 2024, we recorded an impairment of excess and obsolete materials and supplies of $13 million. The impairment related to the write-down of obsolete materials and supplies to fair value using Level 3 inputs in the fair value hierarchy.

We acquired materials and supplies inventory with an estimated value of $30 million in connection with the Aera Merger. See *Note 2 Aera Merger* for additional information.

Assets Held for Sale

We may market certain non-core oil and natural gas assets or other properties for sale. At the end of each reporting period, we evaluate if these assets should be classified as held for sale. The held for sale criteria includes the following: management commitment to a plan to sell, the asset is available for immediate sale, an active program to locate a buyer exists, the sale of the asset is probable and expected to be completed within one year, the asset is being actively marketed for sale and it is unlikely that significant changes will be made to the plan. If all of these criteria are met, the asset is presented as held for sale on our consolidated balance sheet and measured at the lower of the carrying amount or estimated fair vale less costs to sell. DD&A expense is not recorded on assets once classified as held for sale.

The assets classified as held for sale at December 31, 2024 include land acquired for our carbon management activities. See *Note 9 Divestitures and Acquisitions* for more information.

Derivative Instruments

The fair value of our derivative contracts are netted when a legal right of offset exists with the same counterparty with an intent to offset. Since we did not apply hedge accounting to our commodity derivatives for any of the periods presented, we recognized fair value adjustments, on a net basis, in our consolidated statements of operations. Unless otherwise indicated, we use the term “hedge” to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not accounted for as cash-flow or fair-value hedges.

Property, Plant and Equipment (PP&E)

We use the successful efforts method to account for our oil and natural gas properties. Under this method, we capitalize costs of acquiring properties, costs of drilling successful exploration wells and development costs. The costs of exploratory wells, including permitting, land preparation and drilling costs, are initially capitalized pending a determination of whether we find proved reserves. If we find proved reserves, the costs of exploratory wells remain capitalized. Otherwise, we charge the costs of the related wells to expense. In cases where we cannot determine whether we have found proved reserves at the completion of exploration drilling, we conduct additional testing and evaluation of the wells. We generally expense the costs of such exploratory wells if we do not find proved reserves within a one-year period after initial drilling has been completed.

Proved Reserves—Proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a specific 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. We have no proved oil and natural gas reserves for which the determination of economic producibility is subject to the completion of major capital investments.

Several factors could change our proved oil and natural gas reserves. For example, for long-lived properties, higher commodity prices typically result in additional reserves becoming economic and lower commodity prices may lead to existing reserves becoming uneconomic. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded as well as availability of capital to implement the development activities contemplated in the reserves estimates and changes in management's plans with respect to such development activities.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserve estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. These assumptions include estimates of future product prices, which we based on forward price curves and, when applicable, contractual prices, estimates of oil and natural gas reserves and estimates of future expected operating and development costs. Any impairment loss would be calculated as the excess of the asset's net book value over its estimated fair value. We recognize any impairment loss on proved properties by adjusting the carrying amount of the asset.

Unproved Properties—When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved to proved based on the initially determined acquisition cost per BOE. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, regulatory changes, contractual conditions or other factors, the capitalized costs of the related properties would be expensed.

Impairments of unproved properties are primarily based on qualitative factors including intent of property development, lease term and recent development activity. The timing of impairments on unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

Depreciation, Depletion and Amortization—We determine depreciation, depletion and amortization (DD&A) of oil and natural gas producing properties by the unit-of-production method. Our unproved reserves are not subject to DD&A until they are classified as proved properties. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Our gas and power plant assets are depreciated over the estimated useful lives of the assets, using the straight-line method, with expected initial useful lives of the assets of up to 30 years. We depreciated other property and equipment using the straight-line method based on expected useful lives of the individual assets or group of assets. The useful lives typically include ranges of 4-10 years for leasehold improvements, 1-4 years for software and telecommunications equipment and up to 5 years for computer hardware.

We expense annual lease rentals, the costs of injection used in production and exploration, and geological, geophysical and seismic costs as incurred. Costs of maintenance and repairs are expensed as incurred, except that the costs of replacements that expand capacity or add proven oil and natural gas reserves are capitalized.

Stock-Based Incentive Plans

The terms of our long-term incentive plan were approved by our board of directors in January 2021. In accordance with this long-term incentive plan, we reserved 9,257,740 shares of common stock (subject to adjustment) for future issuances to certain executives, employees and non-employee directors that are more fully described in *Note 10 Stock-Based Compensation*.

Earnings Per Share

Basic earnings per share is calculated as net income divided by the weighted average number of our common shares outstanding during the period. Diluted earnings per share is calculated by dividing net income by the weighted average number of our common shares outstanding including the effect of dilutive potential common shares. We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities, when applicable, and the treasury stock method when participating securities are not in place. Certain restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights, which participate at the same rate as common stock.

Under the two-class method, net income allocated to participating securities is subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations (ARO) in the period in which a determination is made that a legal obligation exists to dismantle an asset and reclaim or remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The fair value of the retirement obligation is based on future retirement cost estimates and incorporates many assumptions such as time of abandonment, current regulatory requirements, technological changes, future inflation rates and a risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related PP&E balances. If the estimated future cost or timing of cash flow changes, we adjust the fair value of the liability and PP&E. Over time the liability is increased, and expense is recognized for accretion. The cost capitalized to PP&E is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

We have asset retirement obligations for certain of our facilities, which includes plant and field decommissioning, and the plugging and abandonment of wells. In certain cases, we will recognize ARO in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and, accordingly, we have not recorded a liability.

The following table summarizes the activity related to our 2024 and 2023 ARO:

	Year ended December 31,	
	2024	2023
	(in millions)	
Beginning balance	$ 521	$ 491
Liabilities assumed in the Aera Merger	646	—
Liabilities settled and divested	(94)	(60)
Accretion expense[a]	84	46
Revisions of estimated cash flows	(32)	37
Additions	4	7
Ending balance[b]	$ 1,129	$ 521
Current liability (included in accrued liabilities)	$ 134	$ 99
Non-current liability	$ 995	$ 422

(a) For the year ended December 31, 2024, we recognized a $3 million adjustment in measurement period adjustments related to accretion on the Aera asset retirement obligation.

(b) The table excludes $5 million related to asset retirement obligations associated with assets held for sale at December 31, 2023 that were sold in October 2024. Refer to *Note 9 Divestitures and Acquisitions* for more information on our Ventura divestiture.

Liabilities assumed during 2024 relates to the acquisition of Aera as described in Note 2 *Aera Merger*. Our liabilities settled and divested in 2024 included $92 million related to settlement payments and $2 million related to the divestiture of our Fort Apache real estate property in Huntington Beach, California. Revisions of our estimated cash flows decreased $32 million, which reflects efficiencies gained in how we perform our well abandonment.

Our liabilities settled and divested in 2023 of $60 million, included $51 million for settlement payments and $9 million of liabilities assumed related to our sale of our non-operated working interest in the Round Mountain Unit and a non-producing asset. Revisions of our estimated obligation increased $37 million, which reflected changes in the timing of settlement.

Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to losses in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management's judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management's plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a tax authority. We recognize interest and penalties, if any, related to uncertain tax positions as a component of the income tax provision. No interest or penalties related to uncertain tax positions were recognized in the financial statements for the periods presented.

Production-Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and operating costs. We record a share of production and reserves to recover a portion of such capital and operating costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and operating costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and operating costs. However, our net economic benefit is greater when product prices are higher. These PSCs represented approximately 12% and 18% of our total production for the years ended December 31, 2024 and 2023, respectively.

In line with industry practice for reporting PSCs, we report 100% of operating costs under such contracts in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, which is less than the total volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production equally inflates our revenue and operating costs per barrel and has no effect on our net results.

Pension and Postretirement Benefit Plans

All of our regular, full-time employees participate in postretirement benefit plans we sponsor. These plans are primarily funded as benefits are paid. In addition, a portion of our employees also participate in defined benefit pension plans sponsored by us. We recognize the net overfunded or underfunded amounts in the consolidated financial statements at each measurement date.

We determine our defined benefit pension and postretirement benefit plan obligations based on various assumptions and discount rates. The discount rate assumptions used are meant to reflect the interest rate at which the obligations could effectively be settled on the measurement date. We estimate the rate of return on assets with regard to current market factors but within the context of historical returns.

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market.

Actuarial gains and losses that have not yet been recognized through income, are recorded in accumulated other comprehensive income within equity, net of taxes, until they are amortized as a component of net periodic benefit cost.

Leases

We account for our leases in which we are the lessee, other than mineral leases including oil and natural gas leases, under an accounting standard which requires us to recognize most leases, including operating leases, on the balance sheet. The majority of our leases are for commercial office space, fleet vehicles, drilling rigs, easements and facilities. We categorize leases as either operating or financing at lease commencement. We recognize a right-of-use (ROU) asset and associated lease liability for each operating and finance lease with contractual terms of greater than 12 months on the balance sheet. In considering whether a contract contains a lease, we first consider whether there is an identifiable asset and then consider how and for what purpose the asset would be used over the contract term. Our ROU assets are measured at the initial amount of the lease liability determined by measuring the present value of the fixed minimum lease payments, adjusted for any payments made before or at the lease commencement date, discounted using our incremental borrowing rate (IBR). In determining our IBR, we consider the average cost of borrowing for publicly traded corporate bond yields, which are adjusted to reflect our credit rating, the remaining lease term for each class of our leases and frequency of payments.

The ROU assets for operating leases are amortized over the term of the lease using the straight-line method. Lease expense also includes accretion of the lease liability recognized using the effective interest method. ROU assets are tested for impairment in the same manner as long-lived assets.

Share Repurchase Program

We repurchase shares of our common stock from time to time under a program authorized by our Board of Directors, including pursuant to a contract, instruction or written plan meeting requirements of Rule 10b5-1(c)(1) of the Exchange Act. Share repurchases have not been retired and are displayed separately as treasury stock on our consolidated balance sheet.

Government Grants

Our carbon business has been awarded government grants to assist in developing carbon capture and storage projects, including the evaluation of technology related to direct air capture and determining the suitability of certain reservoirs located in California for carbon storage. We will recognize the government funding as either a reduction of research expense or a reduction to the carrying amount of an asset where equipment is required to be constructed and used during the research period. Grant income is recognized when it is probable the cost will be recovered under the conditions of the agreement, generally when costs are incurred by us. The amounts presented as a reduction of research expenses included in other operating expenses, net in our consolidated statement of operations for the year ended December 31, 2024 and on our balance sheet as of December 31, 2024 are not significant. No amounts have been recognized for asset related grants.

Supplemental Cash Flow Information

Supplemental disclosures to our consolidated statements of cash flows, excluding leases and ARO, are presented below:

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
Supplemental Cash Flow Information			
Interest paid, net of amount capitalized	$ (80)	$ (44)	$ (43)
Income taxes paid	$ 105	$ 121	$ 20
Interest income	$ 18	$ 21	$ 4
Supplemental Disclosure of Non-cash Investing and Financing Activities			
Contribution to the Carbon TerraVault JV	$ 20	$ 15	$ 2
Dividends accrued for stock-based compensation awards	$ 2	$ 3	$ 2
Issuance of shares for stock-based compensation awards	$ 90	$ 5	$ —
Excise tax on share repurchases	$ 2	$ 1	$ —

NOTE 2 AERA MERGER

On July 1, 2024, we obtained by way of merger all of the ownership interests in Aera. We applied the acquisition method of accounting and are the accounting acquirer. The Aera Merger added significant oil-weighted production and proved developed reserves to CRC, primarily in the San Joaquin and Ventura basins.

In connection with the closing of the Aera Merger, we issued 21,315,707 shares of common stock to the Sellers. We expect to issue an additional 346,093 shares for deferred consideration. This deferred consideration is related to pre-effective date and restructuring income taxes of Sellers. Changes in the fair value of this deferred consideration for the six months ended December 31, 2024 was not significant. We also paid approximately $990 million in connection with the extinguishment of all of Aera's outstanding indebtedness using the proceeds from the issuance of our 8.25% senior notes due 2029 (2029 Senior Notes) and cash on hand. The net cash paid by us at legal close to acquire Aera was $853 million, consisting of $990 million to repay Aera's outstanding debt less Aera's cash on hand of $137 million. For more information on the 2029 Senior Notes and recent amendments to our Revolving Credit Facility, refer to *Note 5 Debt.*

As of July 1, 2024, immediately following the closing of the Aera Merger, our existing stockholders prior to the Aera Merger owned 76% of CRC and the Sellers owned 24% of CRC.

At the date of this filing, our assessment of the fair value of assets acquired and liabilities assumed is not complete. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, final appraisals of Aera's assets, measurement of leases, valuation of inventory, valuation of certain accrued liabilities, determination of Aera's asset retirement obligations and preparation of final tax returns that will provide the tax overpayments available to us as well as the underlying tax basis of the assets acquired and liabilities assumed.

During the three months ended December 31, 2024, we recognized measurement period adjustments that decreased asset retirement obligations by $54 million, increased inventories by $12 million, increased other current assets by $40 million, decreased deferred tax liability by $19 million, decreased other noncurrent assets by $9 million, increased accounts payable by $1 million, increased accrued liabilities by $29 million, and decreased other long-term liabilities by $23 million with a decrease to property, plant and equipment, net of $71 million (after an increase in total purchase consideration of $19 million). We recognized $12 million of measurement period adjustments in total operating expenses on our consolidated statement of operations for the year ended December 31, 2024. These adjustments related to additional accretion expense and depreciation, depletion and amortization expense resulting from changes to the purchase price allocation.

We expect to complete the accounting for the purchase during the 12-month period subsequent to the Aera Merger closing date and further adjustments may be made to the provisional amounts recorded as of December 31, 2024. We have measured assets and liabilities at acquisition date fair value on a nonrecurring basis.

The following table summarizes the total purchase consideration:

	Merger Consideration
	(in millions, except share and per share data)
Shares of common stock issued (dividend adjusted)	21,315,707
Common stock per share fair value (on July 1, 2024)	$ 53.28
Fair value of share consideration	$ 1,136
Fair value of Aera debt	990
Deferred consideration obligation	18
Total purchase consideration	$ 2,144

The following table presents the preliminary purchase price allocation to the identifiable assets acquired and the liabilities assumed based on their estimated fair values as of the closing date of the Aera Merger:

	Preliminary Purchase Price Allocation
	(in millions)
Assets Acquired	
Cash	$ 137
Accounts receivable	176
Inventories	30
Other current assets	49
Investment in unconsolidated subsidiary	59
Property, plant and equipment	3,048
Pension and other postretirement benefits	73
Other noncurrent assets	57
Total Assets Acquired	3,629
Liabilities Assumed	
Accounts payable	(158)
Accrued liabilities	(157)
Asset retirement obligations	(646)
Fair value of derivative contracts	(351)
Pension and other postretirement benefits	(35)
Deferred tax liability	(101)
Other long-term liabilities	(37)
Total Liabilities Assumed	(1,485)
Net Assets Acquired	$ 2,144

We recorded cash based on Aera's bank balances as of July 1, 2024, which included restricted cash of $27 million in an escrow account. The measurements for predominately all of the other current and other noncurrent assets acquired and accounts payable, accrued liabilities and other long-term liabilities assumed are based on contracts in place at Aera on the acquisition date. Assets and liabilities related to Aera's pension and other postretirement benefit plans were measured based on actuarial valuations using Level 3 inputs. For more information on Aera's pension and other postretirement benefit plans, see *Note 14 Pension and Postretirement Benefit Plans*.

The fair value of an investment in an unconsolidated subsidiary was based on a preliminary appraisal using both the cost approach and available market data. The fair value of derivative instruments was based on observable inputs, primarily forward commodity-price curves. These inputs are considered Level 2 inputs in the fair value hierarchy.

The fair value of certain acquired property, plant and equipment, primarily consisting of proved oil and natural gas properties, land and corporate assets including software and computer equipment, was based on preliminary appraisals. The fair value of proved oil and natural gas properties as of the acquisition date is based on estimated discounted future net cash flows incorporating market participant assumptions on an after-tax basis. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices, a weighted average cost of capital and a projected inflation rate. When estimating the fair value of proved properties, additional risk adjustments were applied to proved undeveloped reserves to reflect the relative uncertainty of the reserve class. These inputs are classified as Level 3 unobservable inputs, including the underlying commodity price assumptions which are based on the five-year NYMEX forward strip prices, escalated for inflation thereafter, and adjusted for price differentials.

The liability for future asset retirement obligations was determined by calculating the present value of estimated future abandonment costs. We utilized several assumptions, including a credit-adjusted risk-free interest rate, estimated remediation costs, estimated timing of when the work will be performed and a projected inflation rate.

Deferred income taxes represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed. Refer to *Note 8 Income Taxes* for additional information on the deferred tax asset and liability balances.

Lease-related assets and liabilities acquired are remeasured as if the leases were new at the merger date. These agreements are still under review for measurement at an updated incremental borrowing rate. Lease assets are included in property, plant and equipment and the liabilities are included in accrued liabilities and other long-term liabilities.

Supplemental Unaudited Pro Forma Financial Information

The following supplemental unaudited pro forma financial information presents the condensed consolidated results of operations for the years ended December 31, 2024 and 2023 as if the Aera Merger had occurred on January 1, 2023.

	Year ended December 31,	
	2024	2023
	(in millions)	
Total operating revenue	$ 3,883	$ 4,838
Net income	$ 355	$ 721
EPS		
Basic	$ 3.94	$ 7.93
Diluted	$ 3.85	$ 7.65

The pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the Aera Merger been completed on January 1, 2023, nor is it necessarily indicative of future operating results of the combined entity. The pro forma financial information for the years ended December 31, 2024 and 2023 is a result of combining our statements of operations with Aera's pre-merger results from January 1, 2024 and 2023 and includes adjustments for revenues and direct expenses. The pro forma results do not reflect any cost savings anticipated as a result of the Aera Merger and exclude the impact of any severance. The pro forma results include adjustments to depreciation, depletion and amortization (DD&A) based on the purchase price allocated to property, plant, and equipment and the estimated useful lives as well as adjustments to interest and accretion expense. We also included pro forma adjustments for certain compensation-related costs and transaction costs we incurred related to the Aera Merger. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the Aera Merger are properly reflected. Future results may vary significantly from the results reflected in the following pro forma information.

For the period of July 1, 2024 through December 31, 2024, total operating revenue and income before income taxes associated with Aera totaled $1,205 million and $512 million, respectively.

In connection with the Aera Merger, we incurred transaction and integration costs of $57 million and employee severance and related costs of $30 million during the year ended December 31, 2024, which are included in other operating expenses, net on our consolidated statements of operations.

In August 2024, management committed to a reduction in force as part of the integration process following the Aera Merger, which, when complete, will result in a 12% reduction in the combined company's employee headcount. We initiated this workforce reduction to align the size and composition of our workforce with expected future operating and capital plans. In addition, employee severance and related costs includes expenses from a voluntary separation program for eligible employees.

The accelerated vesting of certain awards for former Aera executives was $7 million, and is included in general and administrative expenses for the year ended December 31, 2024. The accelerated vesting was based on existing change of control provisions within the former Aera employee award agreements.

NOTE 3 PROPERTY, PLANT AND EQUIPMENT

We capitalize the costs incurred to acquire or develop our oil and natural gas assets, including ARO and interest. Our total property, plant and equipment increased $3 billion related to our provisional allocation of fair value to assets acquired in the Aera Merger on the acquisition date. We evaluate long-lived assets on a quarterly basis for possible impairment.

Property, plant and equipment, net consisted of the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Proved oil and natural gas properties	$ 6,343	$ 3,156
Facilities and other	395	281
Total property, plant and equipment	6,738	3,437
Accumulated depreciation, depletion and amortization	(1,058)	(667)
Total property, plant and equipment, net	$ 5,680	$ 2,770

Asset Impairments

In 2024, we recognized impairments of $14 million. See *Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for information a $13 million impairment on materials and supplies. Additionally, we had a $1 million impairment related to a non-core asset during the year ended December 31, 2024.

In 2023, we recognized an impairment of $3 million related to land acquired for our carbon management activities. The fair value, using Level 3 inputs in the fair value hierarchy, declined during the first quarter of 2023 due to market conditions (including inflation and rising interest rates).

We recognized an asset impairment of $2 million for the year ended December 31, 2022 related to a write-down of CRC Plaza, a commercial office building located in Bakersfield, California to fair value. In 2022, we sold CRC Plaza for $13 million. See *Note 9 Divestitures and Acquisitions* for further information regarding the sale of CRC Plaza.

NOTE 4 INVESTMENTS AND RELATED PARTY TRANSACTIONS

The following tables present changes to our investments in unconsolidated subsidiaries for the periods presented:

	Midway Sunset Cogeneration Company
	(in millions)
Acquisition Date Fair Value at July 1, 2024	$ 59
Income from investment in unconsolidated subsidiary	2
Distributions	(2)
Investment, December 31, 2024	$ 59

	Carbon TerraVault JV
	(in millions)
Investment, December 31, 2022	$ 13
Loss from investment in unconsolidated subsidiary	(9)
Contributions	15
Investment, December 31, 2023	19
Loss from investment in unconsolidated subsidiary	(12)
Contributions	20
Investment, December 31, 2024	$ 27

Midway Sunset Cogeneration Company

In July 2024, our merger with Aera led to our ownership of Midway Sunset Cogeneration Company, which is a partnership designed to own, manage, and operate a cogeneration facility in Kern County, California. We hold a 50% interest in Midway Sunset Cogeneration Company and San Joaquin Energy Company, a subsidiary of NRG Energy, Inc. (NRG), holds a 50% interest. We determined that Midway Sunset Cogeneration Company is a voting interest entity, where we share decision-making power with San Joaquin Energy Company on all matters that most significantly impact the economic performance of the company. Therefore, we account for our investment in Midway Sunset Cogeneration Company under the equity method of accounting. We recorded our investment at a preliminary fair value of $59 million which was $48 million in excess of Aera's investment in the underlying assets of the partnership. This difference is associated with PP&E and we expect this amount will reverse over the remaining useful life of the power plant. There are no significant transactions between us and Midway Sunset Cogeneration Company.

Carbon TerraVault JV

In August 2022, we entered into a joint venture with BGTF Sierra Aggregator LLC (Brookfield) for the further development of a carbon management business in California (Carbon TerraVault JV). We hold a 51% interest in the Carbon TerraVault JV and Brookfield holds a 49% interest. Our initial contribution included rights to inject CO_2 into the 26R reservoir in our Elk Hills field for permanent CO_2 storage (26R reservoir). Brookfield has contributed $92 million to date. The remaining amount of Brookfield's initial investment will depend on the amount of storage capacity that is permitted subject to certain contractual adjustments.

We determined that the Carbon TerraVault JV is a variable interest entity (VIE); however, we share decision-making power with Brookfield on all matters that most significantly impact the economic performance of the joint venture. Therefore, we account for our investment in the Carbon TerraVault JV under the equity method of accounting. Transactions between us and the Carbon TerraVault JV are related party transactions.

Because the parties have certain put and call rights (repurchase features) with respect to the 26R reservoir if certain milestones are not met, the initial investment (including accrued interest) by Brookfield is reflected as a contingent liability included in other long-term liabilities on our consolidated balance sheets. The contingent liability was $107 million and $52 million at December 31, 2024 and 2023, respectively, inclusive of interest. The joint venture does not have a definitive term and terminates upon either party holding all of the ownership interests in the joint venture.

Both Brookfield and CRC have granted the other party a right to participate in projects that involve the capture, transportation and storage of CO_2 in California. These projects may be developed through the Carbon TerraVault JV or other joint ventures. This right expires upon the earlier of (1) August 2027, (2) when a final investment decision has been approved by the investment committee of the Carbon TerraVault JV for storage projects representing in excess of 5 million metric tons per annum (MMTPA) in the aggregate, or (3) when Brookfield has made contributions to the joint venture in excess of $500 million (unless Brookfield elects to increase its commitment). The non-presenting party has the option to accept, decline or defer its decision to participate. If the decision is deferred, then the presenting party may continue to pursue development; however during this time and prior to a final investment decision, the non-presenting party may elect to participate provided they pay their share of the project development costs incurred up to that point.

The tables below present the summarized financial information related to our equity method investment in the Carbon TerraVault JV (and do not include amounts we have incurred related to development of our carbon management segment, Carbon TerraVault), along with related party transactions for the periods presented.

	December 31, 2024	December 31, 2023
	(in millions)	
Receivables from affiliate[(a)]	$ 46	$ 19
Other long-term liabilities—Contingent liability (related to Carbon TerraVault JV put and call rights)	$ 107	$ 52

(a) Receivable from affiliate includes the remaining amount of Brookfield's initial contributions to the Carbon TerraVault JV which are available to us (either for distribution, borrowing or to offset against future capital calls) and amounts due to us under the MSA (described further below). At December 31, 2024, the amount of $46 million includes $43 million remaining of Brookfield's initial contribution available to us and $3 million related to the MSA and vendor reimbursements. At December 31, 2023, the amount of $19 million includes $17 million remaining of Brookfield's initial contribution available to us and $2 million related to the MSA and vendor reimbursements.

We have a Management Services Agreement (MSA) with the Carbon TerraVault JV whereby we provide administrative, operational and commercial services under a cost-plus arrangement. Services may be supplemented by using third parties and payments to us under the MSA are limited to the amounts in an approved budget. The MSA may be terminated by mutual agreement of the parties, among other events. For the years ended December 31, 2024 and 2023, we invoiced $9 million and $8 million, respectively, to the Carbon TerraVault JV under the MSA for back-office operational and commercial services. These amounts reduced our general and administrative expense and carbon management business expense. There were no amounts invoiced to the Carbon TerraVault JV in 2022.

We are also performing well abandonment work at our Elk Hills field as part of the permitting process for injection of CO_2 at the 26R reservoir. During the years ended December 31, 2024 and 2023, we performed abandonment work and sought reimbursement in the amounts of $14 million and $6 million, respectively, from the Carbon TerraVault JV. We have recorded these reimbursements as a reduction to property, plant and equipment on our consolidated balance sheets.

The underlying net assets of the Carbon TerraVault JV were $309 million and $310 million as of December 31, 2024 and 2023, respectively, which includes cash on hand and PP&E, net of current liabilities. The difference between the carrying value of our investment of $27 million and $19 million at December 31, 2024 and 2023, respectively, and the carrying value of the underlying net assets of the joint venture relates to our accounting for the contribution of the 26R reservoir as a financing arrangement due to the put and call features of the joint venture. The joint venture recognized the contributions by the members at fair value.

NOTE 5 DEBT

As of December 31, 2024 and 2023, our long-term debt consisted of the following:

	December 31, 2024	December 31, 2023	Interest Rate	Maturity
	(in millions)			
Revolving Credit Facility	$ —	$ —	SOFR plus 2.50%-3.50% ABR plus 1.50%-2.50%[(a)]	March 16, 2029
2026 Senior Notes	245	545	7.125%	February 1, 2026
2029 Senior Notes	900	—	8.250%	June 15, 2029
Principal amount	$ 1,145	$ 545		
Unamortized debt discount and issuance costs	(16)	(5)		
Unamortized premium	3	—		
Long-term debt, net	$ 1,132	$ 540		

(a) At our election, borrowings under the amended Revolving Credit Facility may be alternate base rate (ABR) loans or term SOFR loans, plus an applicable margin. ABR loans bear interest at a rate equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent prime rate and (iii) the one-month SOFR rate plus 1%. Term SOFR loans bear interest at term SOFR, plus an additional 10 basis points per annum credit spread adjustment. The applicable margin is adjusted based on the commitment utilization percentage and will vary from (i) in the case of ABR loans, 1.50% to 2.50% and (ii) in the case of term SOFR loans, 2.50% to 3.50%.

Revolving Credit Facility

On April 26, 2023, we entered into an Amended and Restated Credit Agreement (as amended, restated supplemented or modified as of the date hereof, the Revolving Credit Facility) with Citibank, N.A., as administrative agent, and certain other lenders, which amended and restated in its entirety the prior credit agreement, dated October 27, 2020. As of December 31, 2024, our Revolving Credit Facility consisted of a senior revolving loan facility with an aggregate commitment of $1.15 billion. The amount we are able to borrow under our Revolving Credit Facility is limited to the amount of these commitments. Our Revolving Credit Facility also included a sub-limit of $300 million for the issuance of letters of credit. As of December 31, 2024, $167 million letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters. As of December 31, 2024, we had $983 million of availability on our Revolving Credit Facility after taking into account $167 million in letters of credit outstanding. Our borrowing base of $1.5 billion is redetermined semi-annually and was re-affirmed in November 2024 as part of our recent amendment, which is discussed further below.

The proceeds of all or a portion of the Revolving Credit Facility may be used for our working capital needs and for other purposes subject to meeting certain criteria.

Security – The lenders have a first-priority lien on a substantial majority of our assets.

Interest Rate – We can elect to borrow at either an adjusted SOFR rate or an alternate base rate (ABR), plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent prime rate and (iii) the one-month SOFR rate plus 1%. The applicable margin is adjusted based on the borrowing base utilization percentage and will vary from (i) in the case of SOFR loans, 2.5% to 3.5% and (ii) in the case of ABR loans, 1.5% to 2.5%. The unused portion of the facility is subject to a commitment fee which will vary between 0.375% and 0.50% per annum based on the borrowing base utilization. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on SOFR loans is payable at the end of each SOFR period, but not less than quarterly.

Amortization Payments – The Revolving Credit Facility does not include any obligation to make amortizing payments.

Borrowing Base – The borrowing base, currently $1.5 billion, will be redetermined semi-annually each April and October.

Financial Covenants – Our Revolving Credit Facility includes the following financial covenants:

Ratio	Components	Required Levels	Tested
Consolidated Total Net Leverage Ratio	Ratio of Consolidated Total Debt to Consolidated EBITDAX[(a)]	Not greater than 3.00 to 1.00	Quarterly
Current Ratio	Ratio of consolidated current assets to consolidated current liabilities[(b)]	Not less than 1.00 to 1.00	Quarterly

(a) Consolidated EBITDAX is calculated as defined in the Revolving Credit Facility.

(b) The available credit under our Revolving Credit Facility is included in consolidated current assets as part of the calculation of the current ratio.

Other Covenants – Our Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We are also restricted in the amount of cash dividends we can pay on our common stock unless we meet certain covenants included in the Revolving Credit Facility.

Our Revolving Credit Facility, among other things, permits us to make certain restricted payments (such as dividends and share repurchases) and certain investments (including in our carbon management segment); provides for the release of liens on certain assets securing the loans made under the Revolving Credit Facility, including our Elk Hills power plant; permits us to designate the entities that hold certain of our assets, including our Elk Hills power plant, as unrestricted subsidiaries subject to meeting certain conditions; sets the period for which we can enter into hedges on our production at 60 months. In October 2023, we further amended our Revolving Credit Facility to increase our flexibility to incur new indebtedness in the form of term loans secured on a pari passu basis with the obligations under the Revolving Credit Facility. The aggregate amount of such term loans shall not exceed the lesser of the following: (i) the borrowing base then in effect minus the Aggregate Elected Revolving Commitment Amounts (as defined in the Revolving Credit Facility) then in effect and (ii) an amount equal to 33 1/3% of the sum of (A) the Aggregate Elected Revolving Commitment Amounts (as defined in the Revolving Credit Facility) then in effect plus (B) the aggregate term loan exposure of any lender then outstanding.

Our Revolving Credit Facility requires us to maintain hedges on a minimum amount of crude oil production (determined on (i) the date of delivery of annual and quarterly financial statements and (ii) the date of delivery of a reserve report delivered in connection with an interim borrowing base redetermination) of no less than (i) in the event that our Consolidated Total Net Leverage Ratio (as defined in the Revolving Credit Facility) is greater than 2.0:1.0 as of the end of the most recent fiscal quarter test period, 50.0% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period and (ii) in the event that our Consolidated Total Net Leverage Ratio is less than or equal to 2.0:1.0 but greater than 1.5:1.0 as of the end of the most recent fiscal quarter test period, 33.0% of our reasonably anticipated oil production from our proved developed producing reserves for each quarter during the period ending the earlier of (1) the maturity date of the Revolving Credit Facility and (2) 12 months after the delivery of the compliance certificate for the relevant test period. The foregoing minimum hedge requirements do not apply to the extent that our Consolidated Total Net Leverage Ratio is less than or equal to 1.5:1.0 as of the last day of the most recently ended fiscal quarter test period.

Furthermore, the restricted payment and investments covenants permit unlimited investments and/or restricted payments so long as either (a) (i) no Default, Event of Default or Borrowing Base Deficiency shall have occurred and be continuing under the Revolving Credit Facility, (ii) the undrawn availability under the Revolving Credit Facility at such time is not less than 20.0% of the total commitment, (iii) the Consolidated Total Net Leverage Ratio is less than or equal to 2.5:1.0 and (iv) Distributable Free Cash Flow is greater than or equal to zero on such date of determination; or (b) (i) no Default, Event of Default or Borrowing Base Deficiency shall have occurred and be continuing under the Revolving Credit Facility at the time of such investment or restricted payment, (ii) the undrawn availability under the Revolving Credit Facility at such time is not less than 25.0% of the total commitment and (iii) the Consolidated Total Net Leverage Ratio is less than or equal to 1.75:1.0.

Events of Default and Change of Control – Our Revolving Credit Facility provides for certain events of default, including upon a change of control, as defined in the Revolving Credit Facility, that entitles our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

Amendments

In February 2024, in connection with the Aera Merger, we entered into a second amendment to our Revolving Credit Facility to, among other things, permit the incurrence of indebtedness under a bridge loan facility. We did not utilize a bridge loan facility in connection with the Aera Merger and wrote-off $6 million of bridge loan and commitment fees during the year ended December 31, 2024 included in other non-operating (loss) income on our condensed consolidated statement of operations. We capitalized approximately $3 million in deferred financing fees related to this amendment to other assets on our consolidated statement of financial position during the year ended December 31, 2024.

In March 2024, we entered into a third amendment to our Revolving Credit Facility. This amendment facilitated certain matters with respect to the Aera Merger, including the postponement of the regular spring borrowing base redetermination until the fall of 2024 and certain other amendments.

In July 2024, we entered into a fourth amendment to our Revolving Credit Facility as part of the Aera Merger. This amendment increased the aggregate revolving commitments available under the Revolving Credit Facility from $630 million to $1.1 billion. Our ability to borrow under our Revolving Credit Facility is limited to the amount of these commitments. This amendment also increased the borrowing base from $1.2 billion to $1.5 billion, among other matters. We capitalized approximately $7 million in deferred financing fees related to this amendment to other assets on our consolidated statement of financial position during the year ended December 31, 2024.

On November 1, 2024, we entered into a fifth amendment to our Revolving Credit Facility. The amendments included, among other things:

- increasing the amount of the revolving commitments by $50 million to $1,150 million to reflect changes to our lender group;
- extending the maturity date of the facility from July 31, 2027 to March 16, 2029;
- amending the springing maturity to permit our 2026 Senior Notes to remain outstanding past October 31, 2025 so long as the aggregate availability (less the outstanding 2026 Senior Notes) is not less than 25% of the total revolving commitments;
- increasing our capacity to issue letters of credit from $250 million to $300 million; and
- other technical amendments.

We capitalized approximately $7 million in deferred financing fees related to this amendment to other assets on our consolidated statement of financial position during the year ended December 31, 2024.

2026 Senior Notes

On January 20, 2021, we completed an offering of $600 million in aggregate principal amount of our 7.125% senior unsecured notes due 2026 (2026 Senior Notes). The net proceeds of $587 million, after $13 million of debt issuance costs, were used to repay in full our Second Lien Term Loan and EHP Notes, with the remainder used to repay substantially all of the then outstanding borrowings under our Revolving Credit Facility. We recognized a $2 million loss on extinguishment of debt, including unamortized debt issuance costs, associated with these repayments.

Security – Our 2026 Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by certain of our material subsidiaries.

Redemption – We may redeem the 2026 Senior Notes at any time prior to the maturity date at a redemption price equal to (i) 102% of the principal amount if redeemed in the twelve months beginning February 1, 2024 and (ii) 100% of the principal amount if redeemed after February 1, 2025, in each case plus accrued and unpaid interest.

Other Covenants – Our 2026 Senior Notes include covenants that, among other things, restrict our ability to incur additional indebtedness, issue preferred stock, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes.

Events of Default and Change of Control – Our 2026 Senior Notes provide for certain triggering events, including upon a change of control, as defined in the indenture, that would require us to repurchase all or any part of the 2026 Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

2029 Notes Offering and Follow-On Offering

On June 5, 2024, we completed the offering of $600 million in aggregate principal amount of the 2029 Senior Notes. The terms of the 2029 Senior Notes are governed by the indenture, dated as of June 5, 2024, by and among us, the guarantors and Wilmington Trust, National Association, as trustee (2029 Senior Notes Indenture). The net proceeds of $590 million, after $10 million of debt discount and issuance costs, were used along with available cash to repay all of Aera's outstanding debt for approximately $990 million at closing of the Aera Merger. See *Note 2 Aera Merger* for more information on the closing of the Aera Merger.

On August 22, 2024, we completed a follow-on offering of an additional $300 million in aggregate principal amount of 2029 Senior Notes. The net proceeds from this offering of $298 million, after $3 million of debt premium and $5 million of debt issuance costs, were used to repurchase a portion of our 7.125% senior notes due 2026 (2026 Senior Notes). The 2029 Senior Notes issued on August 22, 2024 are governed by the same indenture as the $600 million of 2029 Senior Notes that were previously issued on June 5, 2024.

Security – Our 2029 Senior Notes are general unsecured obligations which are guaranteed on a senior unsecured basis by all of our existing subsidiaries that guarantee our obligations under the Revolving Credit Facility and our existing 2026 Senior Notes.

Redemption – We may redeem the 2029 Senior Notes at any time on or after June 15, 2026 at the redemption prices of (i) 104.125% during the twelve-month period beginning on June 15, 2026, (ii) 102.063% during the twelve-month period beginning on June 15, 2027 and (iii) 100% after June 15, 2028 and before the maturity date. Prior to June 15, 2026, we may redeem up to 35% of the aggregate principal amount of the 2029 Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at the redemption price of 108.250%. In addition, before June 15, 2026, we may redeem some or all of the 2029 Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the 2029 Senior Notes redeemed, plus the applicable premium as specified in the 2029 Senior Notes Indenture and accrued and unpaid interest, if any, to, but excluding, the redemption date.

Other Covenants – Our 2029 Senior Notes include covenants that, among other things, restrict our ability to incur additional indebtedness, issue preferred stock, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions, and enter into transactions that would result in fundamental changes.

Events of Default and Change of Control – Our 2029 Senior Notes provide for certain triggering events, including upon a change of control, as defined in the indenture, that would require us to repurchase all or any part of the 2029 Senior Notes at a price equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Tender Offer and Note Repurchases

In the year ended December 31, 2024, we repurchased $300 million in face value of our 2026 Senior Notes for $303 million, resulting in a loss on early extinguishment of debt in the amount of $5 million which includes a $2 million write-off of unamortized debt issuance costs. In the year ended December 31, 2023, we repurchased $55 million in principal amount of our 2026 Senior Notes at par resulting in an extinguishment loss of $1 million for the write-off of unamortized debt issuance costs.

Our 2026 Senior Notes are redeemable at any time prior to the maturity date at a redemption price equal to (i) 102% of the principal amount if redeemed in the twelve months beginning February 1, 2024, and (ii) 100% of the principal amount if redeemed after February 1, 2025, in each case plus accrued and unpaid interest.

Fair Value

As shown in the table below, we estimate the fair value of our fixed rate 2029 Senior Notes and 2026 Senior Notes based on known prices from market transactions (using Level 1 inputs on the fair value hierarchy).

	December 31, 2024	December 31, 2023
	(in millions)	
Variable rate debt	$ —	$ —
Fixed rate debt		
2026 Senior Notes	245	554
2029 Senior Notes	913	—
Fair Value of Long-Term Debt	$ 1,158	$ 554

Other

At December 31, 2024, all obligations under our Revolving Credit Facility and Senior Notes are guaranteed by certain of our material wholly owned subsidiaries. See *Note 18 Condensed Consolidating Financial Information* for additional information.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

At December 31, 2024, we were in compliance with all debt covenants under our Revolving Credit Facility.

Principal maturities of debt outstanding at December 31, 2024 are as follows:

	As of December 31, 2024
	(in millions)
2025	$ —
2026	245
2027	—
2028	—
2029	900
Thereafter	—
Total	$ 1,145

NOTE 6 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2024 and 2023 were not material to our consolidated balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves cannot be accurately determined.

In October 2020, Signal Hill Services, Inc. defaulted on its decommissioning obligations associated with two offshore platforms. The Bureau of Safety and Environmental Enforcement (BSEE) determined that former lessees, including our former parent, Occidental Petroleum Corporation (Oxy) with a 37.5% share, are responsible for accrued decommissioning obligations associated with these offshore platforms. Oxy sold its interest in the platforms approximately 30 years ago and it is our understanding that Oxy has not had any connection to the operations since that time and challenged BSEE's order. Oxy notified us of the claim under the indemnification provisions of the Separation and Distribution Agreement between us and Oxy. In September 2021, we accepted the indemnification claim from Oxy and are challenging the order from BSEE. In March 2024, we entered into a cost sharing agreement with former lessees to share in ongoing maintenance costs during the pendency of the challenge to the BSEE order. We estimate our ongoing share of maintenance costs for the platforms could be approximately $5 million per year. Due to the preliminary stage of the process, no cost estimates to abandon the offshore platforms have been determined.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, easements related to oil and natural gas segment, obligations under long-term service agreements and field equipment.

At December 31, 2024, total purchase obligations on a discounted basis were as follows:

	December 31, 2024
	(in millions)
2025	$ 40
2026	18
2027	15
2028	15
2029	15
Thereafter	94
Total	197
Less: Interest	(67)
Present value of purchase obligations	$ 130

NOTE 7 DERIVATIVES

We continue to maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices. We also enter into natural gas swaps for the purpose of hedging our fuel consumption in our steamflood operations as well as swaps for natural gas purchases and sales related to our marketing activities. We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2024, 2023 and 2022. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging requirements and program goals, even though they are not accounted for as accounting hedges. Our Revolving Credit Facility includes covenants that require us to maintain a certain level of hedges unless the ratio of our indebtedness to Consolidated EBITDAX is less than or equal to 1.5:1.0. For more information on the requirements of our Revolving Credit Facility, see Note 5 Debt.

Summary of Derivative Contracts

We held the following Brent-based contracts as of December 31, 2024:

	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027	2028
Sold Calls:							
Barrels per day	30,000	30,000	30,000	29,000	15,000	—	—
Weighted-average price per barrel	$ 87.08	$ 87.08	$ 87.08	$ 87.13	$ 85.00	$ —	$ —
Purchased Puts							
Barrels per day	30,000	30,000	30,000	29,000	15,000	—	—
Weighted-average price per barrel	$ 61.67	$ 61.67	$ 61.67	$ 61.72	$ 60.00	$ —	$ —
Swaps							
Barrels per day	52,837	46,506	44,126	42,626	30,449	13,882	1,697
Weighted-average price per barrel	$ 72.48	$ 71.31	$ 70.62	$ 69.94	$ 67.95	$ 65.53	$65.00

The outcomes of the derivative positions are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Swaps – we make settlement payments for prices above the indicated weighted-average price per barrel and receive settlement payments for prices below the indicated weighted-average price per barrel.

At December 31, 2024, we also held the following swaps to hedge purchased natural gas used in our operations as shown in the table below. Financial swaps are purchased to hedge the cost of natural gas used in production of steam-flood crude volumes. The natural gas price index used to hedge each file is based on a number of factors including liquidity and transportation cost.

	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026	2027	2028
SoCal Border							
MMBtu per day	10,000	29,074	25,750	22,408	660	—	—
Weighted-average price per MMBtu	$ 6.02	$ 3.44	$ 3.48	$ 3.53	$ 6.29	$ —	$ —
NWPL Rockies							
MMBtu per day	50,999	51,750	51,750	51,750	44,618	12,616	1,576
Weighted-average price per MMBtu	$ 5.48	$ 2.95	$ 2.95	$ 4.22	$ 4.01	$ 4.34	$ 3.95
PG&E Citygate							
MMBtu per day	14,000	—	—	—	—	—	—
Weighted-average price per MMBtu	$ 6.10	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value of Derivatives

Derivative instruments not designated as hedging instruments are required to be recorded on the balance sheet at fair value. We report gains and losses on our derivative contracts related to our oil production and our marketing activities in operating revenue on our consolidated statements of operations as shown in the table below:

	Year ended December 31, 2024	2023	2022
		(in millions)	
Non-cash commodity derivative gain	$ 274	$ 260	$ 187
Settlements and amortized premiums	(33)	(272)	(738)
Net gain (loss) from commodity derivatives	$ 241	$ (12)	$ (551)

We report gains and losses on our derivative contracts for purchased natural gas used to generate steam for our steamflood operations as a component of operating expense on our consolidated statements of operations. For the years ended December 31, 2024, we recognized a net loss of $30 million (which includes a non-cash gain of $2 million and $32 million of settlement payments). For the year ended December 31, 2023, we recognized a non-cash loss of $8 million. We did not have derivative contracts related to purchased natural gas for our marketing activities during the year ended December 31, 2022.

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented.

The following tables present the fair values of our outstanding commodity derivatives as of December 31, 2024 and December 31, 2023. See Note 2 Aera Merger for the fair value of Aera's acquired derivative contracts on July 1, 2024.

December 31, 2024

Classification	Gross Amounts Recognized	Gross Amounts Offset on the Consolidated Balance Sheet	Net Amounts Presented on the Consolidated Balance Sheet
Assets:		(in millions)	
Other current assets, net	$ 26	$ (12)	$ 14
Other noncurrent assets	32	(16)	16
Liabilities:			
Current - Fair value of derivative contracts	(62)	12	(50)
Other long-term liabilities	(61)	16	(45)
	$ (65)	$ —	$ (65)

December 31, 2023			
Classification	Gross Amounts Recognized	Gross Amounts Offset on the Consolidated Balance Sheet	Net Amounts Presented on the Consolidated Balance Sheet
		(in millions)	
Assets:			
Other current assets, net	$ 39	$ (18)	$ 21
Other noncurrent assets	38	(32)	6
Liabilities:			
Current - Fair value of derivative contracts	(26)	18	(8)
Noncurrent - Fair value of derivative contracts	(34)	32	(2)
	$ 17	$ —	$ 17

Counterparty Credit Risk

As of December 31, 2024, the majority of our credit exposure was with investment-grade counterparties. We actively evaluate the creditworthiness of our counterparties, assign credit limits and monitor exposure against those assigned limits. We believe exposure to credit-related losses was not significant for all periods presented. At December 31, 2024, and 2023, we did not have collateral posted for financial instruments.

NOTE 8 INCOME TAXES

Net income before income taxes, for all periods presented, was generated from domestic operations. The following table summarizes components of our income tax provision:

	Year ended December 31,		
(in millions)	2024	2023	2022
Federal	$ 42	$ 146	$ 10
State and local	27	3	1
Current	69	149	11
Federal	$ 51	$ (12)	$ 141
State and local	20	47	85
Deferred tax provision	71	35	226
Total income tax provision	$ 140	$ 184	$ 237

Income taxes paid by jurisdiction are as follows:

	Year ended December 31,	
	2024	2023
	(in millions)	
Federal	$ 73	$ 120
State and local	32	1
Total taxes paid	$ 105	$ 121

Our effective tax rate differs from the amount computed by applying the U.S. federal income tax statutory rate to income before income taxes as follows:

	Year ended December 31,					
	2024		2023		2022	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory tax rate	$ 108	21%	$ 157	21%	$ 160	21%
State and local income taxes, net of federal income tax effect[a]	38	7	40	5	68	9
Tax credits						
Marginal well credit	(12)	(2)	—	—	(8)	(1)
Other tax credit	—	—	(1)	—	(5)	(1)
Nontaxable or nondeductible items	9	2	6	1	4	1
Change in valuation allowances	—	—	(17)	(2)	17	2
Other adjustments	(3)	(1)	(1)	—	1	—
Effective tax rate	$ 140	27%	$ 184	25%	$ 237	31%

(a) State and local income taxes are predominately in California.

During the year ended December 31, 2023, we released a valuation allowance for a portion of the tax loss on the sale of our Lost Hills assets after we jointly agreed to amend the original tax treatment with the buyer. See *Note 9 Divestitures and Acquisitions* for more information on the Lost Hills transaction. This valuation allowance was initially recorded during the year ended December 31, 2022 for the realizability of a capital loss on the sale of Lost Hills, the deductibility of which was limited. Changes related to the valuation allowance related to state taxes is included as state and local income taxes, net of federal income tax effect in our rate reconciliation above.

The tax effects of temporary differences resulting in deferred income tax assets and liabilities at December 31, 2024 and 2023 were as follows:

	2024		2023	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Property, plant and equipment	$ —	$ (700)	$ 19	$ (286)
Deferred compensation and benefits	66	—	40	—
Asset retirement obligations	342	—	157	—
Interest expense carryforward	158	—	161	—
All other	169	(75)	96	(55)
Total deferred taxes	$ 735	$ (775)	$ 473	$ (341)

We expect to realize our deferred tax assets through future operating income and reversal of taxable temporary differences. The amount of deferred tax assets considered realizable is not assured and could be adjusted if estimates change.

Changes in our deferred tax assets and liabilities during 2024 primarily relates to the acquisition of Aera as described in *Note 2 Aera Merger.* We recorded a net deferred tax liability of $101 million in purchase accounting related to the Aera acquisition and a deferred tax liability of $1 million was recorded to accumulated other comprehensive income related to our pension and other postretirement benefit plans.

Net Operating Loss and Tax Credit Carryforwards

As of December 31, 2024, our U.S. federal net operating loss carryforwards was $29 million, which begins to expire in 2037. Our carryforward for disallowed interest expense of $753 million does not expire.

As of December 31, 2024, our California net operating loss carryforwards was $2 billion, which begins to expire in 2029, and our tax credit carryforwards were $21 million, which begin to expire in 2041. California has suspended the use of net operating loss carryforwards for tax years 2024 through 2026 and also limited the utilization of tax credits up to $5 million per year for the same period.

Our ability to utilize a portion of our net operating loss, tax credit and interest expense carryforwards is subject to an annual limitation. As a result, we recognized a deferred tax asset of $2 million for U.S. federal net operating loss carryforwards (that do not expire) and $24 million for California net operating loss carryforwards. Additionally, we recognized a deferred tax asset for $7 million of our California tax credit carryforwards, included in the all other category in the deferred tax table above. We expect our remaining carryforwards will expire unused.

Other

We did not record a liability for unrecognized tax benefits as of December 31, 2024 and 2023. We remain subject to audit by the Internal Revenue Service for calendar years 2021 through 2023 and by California for calendar years 2020 through 2023.

NOTE 9 DIVESTITURES AND ACQUISITIONS

Divestitures

Fort Apache in Huntington Beach

In March 2024, we sold our 0.9-acre Fort Apache real estate property in Huntington Beach, California for purchase price of $10 million and recognized a $6 million gain.

Ventura

During 2021, 2022 and 2024, we entered into transactions to sell our Ventura basin assets. The Ventura divestiture contemplated multiple closings that were subject to customary closing conditions. The closings that occurred in the second half of 2021 resulted in the divestiture of the vast majority of our Ventura basin assets. The transfer of the remaining assets in the Ventura basin was approved in June 2024 by the State Lands Commission. On October 14, 2024, we completed the sale of the Ventura basin assets and recognized a $4 million gain. During the year ended December 31, 2022, we recognized a gain of $11 million related to the sale of additional Ventura basin assets.

Round Mountain Unit

On December 29, 2023, we entered into an agreement to sell our non-operated working interest in the Round Mountain Unit in the San Joaquin basin, recognizing a gain of $25 million. We retained an option to capture, transport and store CO_2 emissions from the production at Round Mountain Unit for future carbon management projects. This option can be terminated by the buyer after January 1, 2028.

Lost Hills

On February 1, 2022, we sold our 50% non-operated working interest in certain horizons within our Lost Hills field, located in the San Joaquin basin, recognizing a gain of $49 million. We retained an option to capture, transport and store 100% of the CO_2 from steam generators across the Lost Hills field for future carbon management projects. This option can be terminated by the buyer after January 1, 2026. We also retained 100% of the deep rights and related seismic data.

CRC Plaza

In 2022, we sold our commercial office building located in Bakersfield, California for net proceeds of $13 million, recognizing no gain or loss on the sale following recognition of impairment charges in 2022. We also leased back a portion of the building with a term of 18 months. See *Note 3 Property, Plant and Equipment* for details of impairment charges we recognized prior to the sale of this property.

Other Divestitures

In 2024, we sold non-core assets recognizing a $1 million gain. In 2023, we sold a non-producing asset in exchange for the assumption of liabilities recognizing a $7 million gain. In 2022, we sold non-core assets recognizing a $1 million loss.

Acquisitions

In 2024, we acquired land for our carbon management segment for approximately $6 million. In 2023, we acquired land for our carbon management segment for approximately $5 million. In 2022, we acquired land for our carbon management segment for approximately $17 million, with the intent to divest a portion of the surface acreage at that time. We classified a portion of this surface acreage as held for sale, recording these assets at fair value and recognizing an impairment of $3 million in the first quarter of 2023. The fair value, using Level 3 inputs in the fair value hierarchy, declined during the first quarter of 2023 due to market conditions (including inflation and rising interest rates). During the fourth quarter of 2024, we marketed the remaining surface acreage and also included these assets as held for sale. We reduced the carrying value of the surface acreage to fair value and recognized an impairment charge of $1 million during the fourth quarter of 2024. The fair value, using Level 3 inputs in the fair value hierarchy, declined due to market conditions. The assets being divested continue to be actively marketed and remain classified as held for sale as of December 31, 2024 on our consolidated balance sheet.

NOTE 10 STOCK-BASED COMPENSATION

On January 18, 2021, our Board of Directors approved the California Resources Corporation 2021 Long Term Incentive Plan (Long Term Incentive Plan). The Long Term Incentive Plan provides for potential grants of stock options, stock appreciation rights, restricted stock awards, restricted stock units, vested stock awards, dividend equivalents, other stock-based awards and substitute awards to employees, officers, non-employee directors and other service providers of the Company and its affiliates.

The Long Term Incentive Plan provides for the reservation of 9,257,740 shares of common stock for future issuances, subject to adjustment as provided in the Long Term Incentive Plan. Shares of stock subject to an award under the Long Term Incentive Plan that expires or is cancelled, forfeited, exchanged, settled in cash or otherwise terminated without the actual delivery of shares (restricted stock awards are not considered “delivered shares” for this purpose) will again be available for new awards under the Long Term Incentive Plan. However, (i) shares tendered or withheld in payment of any exercise or purchase price of an award or taxes relating to awards, (ii) shares that were subject to an option or a stock appreciation right but were not issued or delivered as a result of the net settlement or net exercise of the option or stock appreciation right, and (iii) shares repurchased on the open market with the proceeds from the exercise price of an option, will not, in each case, again be available for new awards under the Long Term Incentive Plan.

Shares of our common stock may be withheld by us in satisfaction of tax withholding obligations arising upon the vesting of restricted stock units (RSUs) and performance stock units (PSUs).

Stock-based compensation expense is recorded on our consolidated statements of operations based on job function of the employees receiving the grants as shown in the table below.

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
General and administrative expenses	$ 32	$ 40	$ 26
Operating costs	6	7	4
Carbon management business expenses	2	1	—
Total stock-based compensation expense	$ 40	$ 48	$ 30
Income tax benefit	$ 8	$ 9	$ 6

We paid $18 million, $11 million, and $6 million for our long-term cash incentive awards for the years ended December 31, 2024, December 31, 2023, and December 31, 2022, respectively.

Stock Settled Awards

Restricted Stock Units

Executives and non-employee directors were granted RSUs, which are in the form of, or equivalent in value to, actual shares of our common stock. The awards generally vest from two to three years following the grant date. Dividend equivalents are accumulated and paid when the shares are issued.

The following table sets forth RSU activity for the year ended December 31, 2024:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2023	1,288	$ 29.49
Granted	219	$ 54.28
Vested	(860)	$ 27.35
Forfeited or Cancelled	(4)	$ 45.91
Unvested at December 31, 2024	643	$ 40.36

Compensation expense was measured on the date of grant using the quoted market price of our common stock and is primarily recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any.

As of December 31, 2024, the unrecognized compensation expense for our unvested RSUs was approximately $10 million and is expected to be recognized over a weighted-average remaining service period of approximately two years.

Performance Stock Units

In 2024 and 2023, executives were granted PSUs which are earned based on our absolute total shareholder return and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. The PSUs have payouts that range from 0% to 200% of the target award and settle in common shares once certified. Dividend equivalents for these awards are accumulated and paid out upon certification of the award.

In 2022, executives were granted PSUs which are earned upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock generally during a three-year service period commencing on the grant date. Once units are earned, the earned units are not reduced for subsequent decreases in stock price. For the duration of the three-year period, a minimum of 0% and a maximum of 100% of the PSUs granted could be earned. The grant date fair value and associated equity compensation expense was measured using a Monte Carlo simulation model which runs a probabilistic assessment of the number of units that will be earned based on a projection of our stock price during the three-year service period. Although certain events may accelerate vesting, earned PSUs generally vest on the third anniversary of the grant date, and are settled in shares of our common stock at the three-year anniversary of the grant date.

The following table sets forth PSU activity for the year ended December 31, 2024:

	Number of Units	Weighted-Average Grant-Date Fair Value
	(in thousands)	
Unvested at December 31, 2023	1,373	$ 28.13
Granted	281	$ 59.00
Vested	(869)	$ 19.66
Forfeited or Cancelled	(21)	$ 38.00
Unvested at December 31, 2024	764	$ 48.83

The range of assumptions used in the valuation of PSUs granted during 2024, 2023 and 2022 were as follows:

	2024	2023	2022
Expected volatility[(a)]	38.58% - 40.30%	42.36% - 55.00%	60.00%
Risk-free interest rate[(b)]	4.52% - 4.86%	3.81% - 4.95%	1.59% - 2.55%
Dividend yield[(c)]	— %	— %	— %
Forecast period (in years)	2.5 - 3	1.5 - 3	2 - 3

(a) Expected volatility was calculated using the historic volatility of a peer group due to our limited trading history since our emergence from bankruptcy. We included the historic volatility of our stock, excluding our first two trading months, in the peer group. Expected volatility was calculated using the historic volatility of our stock beginning in 2023 for certain awards as we established enough stock history.

(b) Based on the U.S. Treasury yield for a two- or three-year term at the grant date, as applicable.

(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

Compensation expense is recognized on a straight-line basis over the requisite service periods adjusted for actual forfeitures, if any. Events that accelerate the vesting of an award have no effect on the requisite service period until such an event becomes probable.

As of December 31, 2024, the unrecognized compensation expense for our unvested PSUs was approximately $16 million and is expected to be recognized over a weighted-average remaining service period of approximately two years.

Cash Incentive Awards

In each of the years of 2024, 2023 and 2022, we granted performance cash-settled awards to approximately 500 non-executive employees where half of the award is variable with payouts ranging from 75% to 150% of the grant value. The variable portion of the award is determined based upon the attainment of specified 60-trading day volume weighted average prices for shares of our common stock preceding each vesting date. These awards vest ratably over a three-year service period, with one third of the grants vesting on each of the first three anniversaries of the grant date. The fair value of the awards is adjusted on a quarterly basis for the cumulative change in the value determined using a Monte Carlo simulation model which runs a probabilistic assessment of our stock price for each of the three-year service periods.

The assumptions used in the valuation of our cash awards as of December 31, 2024 were as follows:

	2024 Awards	2023 Awards	2022 Awards
Expected volatility[(a)]	35 %	37 %	38 %
Risk-free interest rate[(b)]	4.25 %	4.17 %	4.24 %
Dividend yield[(c)]	— %	— %	— %
Forecast period (in years)	2.15	1.15	0.5

(a) Expected volatility was calculated using the historical volatility of our stock.
(b) Based on the U.S. Treasury yield for the remaining terms.
(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

As of December 31, 2024, the unrecognized compensation expense for all of our unvested cash-settled awards was $11 million and is expected to be recognized over a weighted-average remaining service period of approximately two years. The value of awards forfeited during the year ended December 31, 2024 was approximately $3 million.

Aera Incentive Awards

Upon closing of the Aera Merger we assumed cash-settled incentive awards that had been granted to certain Aera employees. The awards were granted by Aera in 2022, 2023, and 2024 and vest ratably over periods between two to three years. Awards that vested prior to July 1, 2024 were earned based on the performance metrics of Aera and we assumed a liability of $8 million for the vested awards. Following July 1, 2024, the unvested awards will be earned based on our absolute total shareholder return and total shareholder return relative to the SPDR S&P Oil and Gas Exploration and Production Exchange-Traded Fund listed on the New York Stock Exchange. The awards pay out between 0% to 200%.

	2024 Awards	2023 Awards
Expected volatility[(a)]	34.81 %	38.53 %
Risk-free interest rate[(b)]	4.25 %	4.16 %
Dividend yield[(c)]	— %	— %
Forecast period (in years)	2.00	1

(a) Expected volatility was calculated using the historical volatility of our stock.
(b) Based on the U.S. Treasury yield for the remaining terms.
(c) A dividend adjusted stock price (assumed reinvestment of dividends during the performance period) was used.

As of December 31, 2024, the unrecognized compensation expense for these cash-settled awards was approximately $5 million and is expected to be recognized over a weighted-average remaining service period of 1.6 years.

Employee Stock Purchase Plan

In May 2022, our shareholders approved a new California Resources Corporation Employee Stock Purchase Plan (ESPP), which took effect in July 2022. The ESPP provides our employees with the ability to purchase shares of our common stock at a price equal to 85% of the closing price of a share of our common stock as of the first or last day of each fiscal quarter, whichever amount is less. The maximum number of shares of our common stock which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 1,250,000 shares.

As of December 31, 2024, a total of 95,750 common shares were issued under our ESPP.

NOTE 11 STOCKHOLDERS' EQUITY

The following is a summary of changes in our common shares outstanding:

	Common Shares Outstanding
Balance, December 31, 2022	71,949,742
Shares issued for warrant exercises	35,441
Shares issued under ESPP	41,013
Shares issued under stock-based compensation arrangements	75,344
Treasury stock - shares repurchased	(3,407,655)
Balance, December 31, 2023	68,693,885
Issued as part of the Aera Merger	21,315,707
Shares issued for warrant exercises	3,769,703
Shares issued under ESPP	38,257
Shares issued under stock-based compensation arrangements[a]	1,740,189
Treasury stock - shares repurchased	(3,649,348)
Shares cancelled for taxes	(808,071)
Balance at December 31, 2024	91,100,322

(a) A significant number of stock-based compensation awards were settled in the first quarter of 2024. These awards were primarily granted in January 2021 following our emergence from bankruptcy.

Share Repurchase Program

Our Board of Directors authorized a Share Repurchase Program to acquire up to $1.35 billion of our common stock through December 31, 2025. The repurchases may be effected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, derivative contracts or otherwise in compliance with Rule 10b-18, subject to market conditions. The Share Repurchase Program does not obligate us to repurchase any dollar amount or number of shares and our Board of Directors may modify, suspend, or discontinue authorization of the program at any time. The following is a summary of our share repurchases, held as treasury stock, for the periods presented:

	Total Number of Shares Purchased	Dollar Value of Shares Purchased	Average Price Paid per Share
	(number of shares)	(in millions)	($ per share)
Year ended December 31, 2022	7,366,272	$313	$42.47
Year ended December 31, 2023	3,407,655	$143	$41.69
Year ended December 31, 2024	3,649,348	$192	$52.12
Inception of Program (May 2021) through December 31, 2024	18,513,263	$796	$42.82

Note: The total value of shares purchased includes approximately $2 million and $1 million in the years ended December 31, 2024 and 2023 related to excise taxes on share repurchases, which was effective beginning in 2023. Commissions paid were not significant in all periods presented.

Dividends

Dividends are payable to shareholders in quarterly increments, subject to the quarterly approval of our Board of Directors. The actual declaration of future cash dividends, and the establishment of record and payment dates, is subject to final determination by our Board of Directors each quarter after reviewing our financial performance. See *Note 19 Subsequent Events* for information on future cash dividends.

Our Board of Directors declared quarterly cash dividends of $0.17 per share of common stock for each of the first three quarters of 2022. On November 2, 2022, our Board of Directors approved an increase in our dividend policy to an expected total annual dividend of $1.13 per share. On November 1, 2023, our Board of Directors increased our dividend policy to an expected total annual dividend of $1.24 per share. On August 2, 2024, our Board of Directors increased the cash dividend policy to anticipate a total annual dividend of $1.55 per share.

Our Board of Directors declared the following cash dividends for each of the periods presented.

	Total Dividend	Annual Rate Per Share
	(in millions)	($ per share)
Year ended December 31, 2022	59	$ 0.7925
Year ended December 31, 2023	81	$ 1.1575
Year ended December 31, 2024	113	$ 1.3950
	$ 253	

Warrants

In October 2020, we reserved an aggregate 4,384,182 shares of our common stock for issuance upon the exercise of warrants, which were exercisable at $36 per share through October 28, 2024. As of December 31, 2024, we had no outstanding warrants.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of after-tax amounts for our pension and postretirement benefit plans. See *Note 14 Pension and Postretirement Benefit Plans* for further information.

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
Beginning accumulated other comprehensive income	$ 74	$ 81	$ 72
Actuarial gain (loss) associated with pension and postretirement	4	(2)	18
Prior service credit	3	—	—
Recognition of prior service credit due to curtailment	—	(3)	—
Recognition of net actuarial gain due to curtailment	(4)	—	—
Recognition of net actuarial loss due to special termination benefits	4	—	—
Amortization of prior service credit	(5)	(5)	(5)
Other comprehensive income (loss)	2	(10)	13
Total recorded in accumulated other comprehensive income, before tax	76	71	85
Income tax (provision) benefit	(1)	3	(4)
Total recorded in accumulated other comprehensive income, net of tax	$ 75	$ 74	$ 81

NOTE 12 EARNINGS PER SHARE

Basic and diluted earnings per share (EPS) were calculated using the treasury stock method. Our restricted and performance stock unit awards, as described in *Note 10 Stock-Based Compensation*, are not considered participating securities since the dividend rights on unvested shares are forfeitable.

For basic EPS, the weighted-average number of common shares outstanding excludes underlying shares related to equity-settled awards and warrants. For diluted EPS, the basic shares outstanding are adjusted by adding potential common shares, if dilutive. Under the treasury stock method, we assume that proceeds from the exercise of options, warrants and similar instruments are used to purchase common stock at average market price of our stock each period. For PSUs, we measure the performance of our common stock against certain market conditions to determine the percentage earned for each period and the number of potential common shares included in diluted EPS. An insignificant number of potential common shares were not earned, and therefore were not treated as issued in our diluted EPS calculation for the year ended December 31, 2024.

The following table presents the calculation of basic and diluted EPS.

	Year ended December 31,		
	2024	2023	2022
	(in millions, except per share amounts)		
Numerator for Basic and Diluted EPS			
Net income	$ 376	$ 564	$ 524
Denominator for Basic EPS			
Weighted-average shares	79.3	69.6	75.5
Potential dilutive common shares:			
Restricted Stock Units	0.5	1.0	0.7
Performance Stock Units	0.5	0.9	0.7
Warrants	1.0	1.0	0.7
Deferred Consideration Obligation (related to the Aera Merger)	0.1	—	—
Denominator for Diluted Earnings per Share			
Weighted-average shares - diluted	81.4	72.5	77.6
EPS			
Basic	$ 4.74	$ 8.10	$ 6.94
Diluted	$ 4.62	$ 7.78	$ 6.75

NOTE 13 LEASES

We have operating leases primarily for carbon sequestration easements, drilling rigs, vehicles and commercial office space. ASC 805 *Business Combinations*, requires lease-related assets and liabilities acquired to be measured as if the lease were new at the acquisition date, using our incremental borrowing rate. The Aera leases are still being evaluated. We intend for leases acquired through the acquisition to retain the previous lease classification.

We have recorded the following amounts on our balance sheet as of December 31, 2024 and 2023:

	Classification	2024	2023
		(in millions)	
Assets			
Operating lease, net	*Other noncurrent assets*	$ 105	$ 73
Finance lease, net	*PP&E*	3	—
Total lease assets		$ 108	$ 73
Liabilities			
Current			
Operating lease	*Accrued liabilities*	$ 15	$ 15
Finance lease	*Accrued liabilities*	1	—
Long-term			
Operating lease	*Other long-term liabilities*	$ 76	$ 55
Finance lease	*Other long-term liabilities*	2	—
Total lease liabilities		$ 94	$ 70

We combine lease and nonlease components in determining fixed minimum lease payments for our drilling rigs and commercial office space. If applicable, fixed minimum lease payments are reduced by lease incentives for our commercial office space and increased by mobilization and demobilization fees for our drilling rigs. Certain of our lease agreements include options to extend or terminate the lease, which we may exercise at our sole discretion. For our existing leases, we did not include these options in determining our fixed minimum lease payments over the lease term. Our leases do not include options to purchase the leased property. Lease agreements for our fleet vehicles include residual value guarantees, none of which are recognized in our financial statements until the underlying contingency is resolved. In addition, we have entered into easements with respect to our carbon management segment. Our right-of-use asset for these easements was $57 million and $36 million for the years ended December 31, 2024 and 2023, respectively.

Variable lease costs for our drilling rigs include costs to operate, move and repair the rigs. Variable lease costs for commercial office space include utilities and common area maintenance charges. Variable lease costs for our fleet vehicles include other-than-routine maintenance and other various amounts in excess of our fixed minimum rental fee.

Our lease costs, including amounts capitalized to PP&E, shown in the table below are before joint-interest recoveries. Lease payments are reduced by joint interest recoveries on our consolidated statement of operations through our joint-interest billing process.

	Year ended December 31,	
	2024	2023
	(in millions)	
Operating lease costs	$ 26	$ 23
Short-term lease costs[a]	50	52
Variable lease costs	2	2
Total operating lease costs	78	77
Finance lease costs	1	—
Sublease income	(2)	(2)
Total lease costs	$ 77	$ 75

(a) Contracts with terms of less than one month or less are excluded from our disclosure of short-term lease costs.

We sublease certain commercial office space to third parties where we are the primary obligor under the head lease. The lease terms on those subleases never extend past the term of the head lease and the subleases contain no extension options or residual value guarantees. Sublease income is recognized based on the contract terms and included as a reduction of operating lease cost under our head lease.

Other supplemental information related to our operating leases as of December 31, 2024 and 2023 is provided below:

	Year ended December 31,	
	2024	2023
	(in millions)	
Cash paid for lease liabilities		
Lease liabilities associated with operating activities	$ 29	$ 28
Lease liabilities associated with investing activities	$ 8	$ 2
Lease liabilities associated with financing activities	$ 1	$ —
ROU assets obtained in exchange for new operating lease liabilities	$ 52	$ 32
ROU assets obtained in exchange for new finance lease liabilities	$ 3	$ —

	2024	2023
Operating Leases		
Weighted-average remaining lease term (in years)	5.95	7.34
Weighted-average discount rate	8.1 %	6.7 %
Finance Leases		
Weighted-average remaining lease term (in years)	3.37	—
Weighted-average discount rate	9.0 %	—%

Our operating and finance lease payments as of December 31, 2024 are as follows:

	Operating Leases	Finance Leases
	(in millions)	
2025	$ 27	$ 1
2026	25	1
2027	19	1
2028	17	—
2029	12	—
Thereafter	23	—
Less: Interest	(24)	—
Present value of lease liabilities	$ 99	$ 3

NOTE 14 PENSION AND POSTRETIREMENT BENEFIT PLANS

Prior to the Aera Merger, we maintained two qualified defined benefit pension plans covering union employees and a postretirement health care plan for certain retired employees. In connection with the Aera Merger, we acquired a qualified defined benefit cash balance pension plan and a non-qualified cash balance pension plan that restores benefits lost due to governmental limitations on the qualified plan. We also acquired two postretirement benefit plans that provide health care benefits for certain retired employees. Certain of the postretirement benefit obligations are funded through 401(h) accounts under the qualified pension plans. Aera's pension and postretirement obligations were remeasured as of the July 1, 2024 acquisition date. At that time, for Aera's pension plans, we recognized a net benefit asset of $64 million and a net benefit liability of $8 million and for Aera's postretirement benefit plans, we recognized a net benefit asset of $9 million and a net benefit liability of $27 million. Accumulated other comprehensive income balances for the acquired Aera plans were eliminated in purchase accounting.

In August 2024, we amended Aera's pension and postretirement benefit plans. For Aera's defined benefit pension plans and post age 65 postretirement benefit plan, participants no longer accrue additional benefits for service after September 30, 2024. However, for each of the foregoing plans, future service will count towards vesting of benefits accrued based on past service. In addition, for both of Aera's postretirement benefit plans, we expanded the eligibility provisions in the event of an involuntary layoff. Following the Aera Merger, we recognized a curtailment gain of $4 million and a one-time cost of special termination benefits of $4 million included in net periodic benefit costs for the year ended December 31, 2024.

Defined Contribution Plans

All of our employees are eligible to participate in our tax-qualified, defined contribution retirement plan that provides for periodic cash contributions by us based on annual cash compensation and employee deferrals.

Certain salaried employees participate in non-qualified supplemental defined contribution plans that restore benefits lost due to government limitations on qualified plans. We recognized $30 million and $24 million in other long-term liabilities for the years ended December 31, 2024 and 2023, respectively, related to these supplemental plans.

We expensed $27 million in 2024, $19 million in 2023 and $18 million in 2022 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2024, approximately 800 employees accrued benefits under these plans primarily in connection with the acquired Aera pension plans. As a result of the amendments made in September 2024 to the acquired Aera pension plans, only approximately 60 employees were accruing benefits at year-end, all of whom were union employees.

Pension costs for the defined benefit pension plans, determined by independent actuarial valuations, are funded by us through payments to trust funds, which are administered by independent trustees.

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. Our former employees are required to make monthly contributions for the coverage, but the benefits are primarily funded by us as claims are paid during the year.

Obligations and Funded Status of our Defined Benefit Plans

The following table shows the amounts recognized on our balance sheets related to pension and postretirement benefit plans, as well as plans that we or our subsidiaries sponsor:

	December 31, 2024		December 31, 2023	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)		(in millions)	
Amounts recognized on the balance sheet				
Other assets	$ 67	$ 13	$ 2	$ —
Accrued liabilities	(1)	(6)	—	(3)
Other long-term liabilities	(6)	(53)	(3)	(33)
	$ 60	$ (46)	$ (1)	$ (36)
Accumulated other comprehensive income, net of tax	$ 2	$ 73	$ 2	$ 72

The following table shows the funding status of our pension and post-retirement benefit plans along with a reconciliation of our benefit obligations and changes in fair value of plan assets:

	Year ended December 31,	
	2024	2023
	(in millions)	
Pension		
Changes in the benefit obligation		
Benefit obligation - beginning of year	$ 34	$ 30
Liabilities assumed in the Aera Merger	249	—
Service cost - benefits earned during the period	3	1
Interest cost on projected benefit obligation	8	1
Actuarial (gain) loss[(a)]	(2)	3
Benefits paid	(20)	(1)
Benefit obligation - end of year	$ 272	$ 34
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 34	$ 32
Additions due to the Aera Merger	305	—
Actual return on plan assets	10	3
Employer contributions	3	—
Benefits paid	(20)	(1)
Fair value of plan assets - end of year	$ 332	$ 34
Net benefit asset	$ 60	$ —
Postretirement		
Changes in the benefit obligation		
Benefit obligation - beginning of year	$ 37	$ 38
Liabilities assumed in the Aera Merger	70	—
Service cost - benefits earned during the period	2	2
Interest cost on projected benefit obligation	4	2
Actuarial gain[(b)]	(5)	(2)
Cost of special termination benefits	4	—
Curtailment gain	(4)	—
Benefits paid	(5)	(3)
Plan amendment	(3)	—
Benefit obligation - end of year	$ 100	$ 37
Changes in plan assets		
Fair value of plan assets - beginning of year	$ 1	$ 1
Additions due to the Aera Merger	52	—
Actual gain (loss) on plan assets	2	—
Employer contributions	4	3
Benefits paid	(5)	(3)
Fair value of plan assets - end of year	$ 54	$ 1
Net benefit liability	$ (46)	$ (36)

(a) The gain reflected in the changes in the pension benefit obligation for the year ended December 31, 2024 was primarily due to movement in the discount rates.

(b) The gain reflected in the changes in the postretirement benefit obligation for the year ended December 31, 2024 was primarily due to movement in the discount rate.

The following table sets for the details of our obligations and assets related to our defined benefit pension plans for the years ended December 31:

	2024	2023
	(in millions)	
Projected benefit obligation	$ 272	$ 34
Accumulated benefit obligation	$ 268	$ 30
Fair value of plan assets	$ 332	$ 34

Components of Net Periodic Benefit Cost

We record the service cost component of net periodic pension cost with other employee compensation and all other components, including settlement costs, are reported as other non-operating income (expenses), net on our consolidated statements of operations. The following table set forth the components of our net periodic pension and postretirement benefit costs:

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
Pension			
Net periodic benefit costs			
Service cost - benefits earned during the period	$ 3	$ 1	$ 1
Interest cost on projected benefit obligation	8	1	1
Expected return on plan assets	(13)	(2)	(1)
Net periodic benefit costs	$ (2)	$ —	$ 1
Postretirement			
Net periodic benefit costs			
Service cost - benefits earned during the period	$ 2	$ 2	$ 2
Interest cost on projected benefit obligation	4	2	1
Expected return on plan assets	(2)	—	—
Cost of special termination benefits	4	—	—
Amortization of prior service cost credit	(5)	(5)	(5)
Amortization of net actuarial gain	(1)	(2)	—
Curtailment gain	(4)	(3)	—
Net periodic benefit costs	$ (2)	$ (6)	$ (2)

Components of accumulated other comprehensive income (loss) (AOCI) are presented net of tax. The following table presents the changes in plan assets and benefit obligations recognized in other comprehensive (loss) income:

	Year ended December 31,		
	2024	2023	2022
		(in millions)	
Pension			
Net actuarial (gain) loss	$ —	$ (1)	$ 4
Total	$ —	$ (1)	$ 4
Postretirement			
Net actuarial (gain) loss	$ (5)	$ 1	$ 9
Prior service credit	(3)	—	—
Actuarial net gain due to curtailment	4	—	—
Special termination benefits	(4)	—	—
Amortization of prior service credit due to curtailment	—	(2)	—
Amortization of prior service credit	5	(4)	(4)
Amortization net actuarial gain (loss)	2	(1)	—
Total	$ (1)	$ (6)	$ 5

The following table sets forth the valuation assumptions, on a weighted-average basis, used to determine our benefit obligations and net periodic benefit cost:

	Year ended December 31,	
	2024	2023
Pension		
Benefit Obligation Assumptions		
Discount rate	5.61 %	4.98 %
Rate of compensation increase	4.93 %	4.00 %
Interest crediting rate	5.28 %	N/A
Net Periodic Benefit Cost Assumptions		
Discount rate	5.22 %	5.19 %
Expected return on assets	7.00 %	6.98 %
Rate of compensation increase	4.96 %	4.00 %
Interest crediting rate	6.37 %	N/A
Postretirement		
Benefit Obligation Assumptions		
Discount rate	5.50 %	4.99 %
Net Periodic Benefit Cost Assumptions		
Discount rate	5.13 %	5.20 %
Expected return on assets	6.99 %	6.50 %

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the FTSE Above Median AA yield curve in 2024 and in 2023. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in pension plans that determine benefits using compensation. The assumed return on assets is estimated with regard to current market factors but within the context of historical returns for the asset mix that exists at year end.

In 2024 and 2023, we used the Society of Actuaries Pri-2012 mortality assumptions reflecting the MP-2021 scale which plan sponsors in the U.S. use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 2.45% and 2.38% as of December 31, 2024 and 2023, respectively. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that, as of December 31, 2024, health care cost trend rates would be 6.50% in 2025 decreasing until they reach 4.50% in 2033 and remain at 4.50% thereafter. For those union employees, we projected that, as of December 31, 2023, health care cost trend rates would be 6.75% in 2024 decreasing until they reach 4.50% in 2033 and remain at 4.50% thereafter.

The actuarial assumptions used could change in the near term as a result of changes in expected future trends and other factors that, depending on the nature of the changes, could cause increases or decreases in the plan assets and liabilities.

Fair Value of Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In 2024 and 2023, the target allocation of pension plan assets was 45% and 50% equity securities and 55% and 50% debt securities, respectively. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

The fair values of our pension plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2024			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class	(in millions)			
Comingled funds				
Bonds	24	162	—	186
Commodities	17	—	—	17
U.S. equity	—	84	—	84
International equity	24	20	—	44
Total pension plan assets	$ 65	$ 266	$ —	$ 331

	Fair Value Measurements at December 31, 2023			
	Level 1	**Level 2**	**Level 3**	**Total**
Asset Class	(in millions)			
Commingled funds				
Bonds	—	18	—	18
Commodities	—	—	—	—
U.S. equity	—	6	—	6
International equity	—	10	—	10
Total pension plan assets	$ —	$ 34	$ —	$ 34

The fair values of our postretirement benefit plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2024			
	Level 1	Level 2	Level 3	Total
Asset Class	(in millions)			
Comingled funds				
Bonds	4	26	—	30
Commodities	3	—	—	3
U.S. equity	—	13	—	13
International equity	4	2	—	6
Total pension plan assets	$ 11	$ 41	$ —	$ 52

Our postretirement benefit plan assets of $1 million in 2023 were invested in mutual funds (Level 1 on the fair value hierarchy) with target allocations of 40% equities and 60% debt securities.

Expected Contributions and Benefit Payments

In 2025, we expect to contribute $1 million to our pension plans and expect to contribute $7 million to our postretirement benefit plans. Estimated future undiscounted benefit payments by the plans, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits	Postretirement Benefits
For the years ended December 31,	(in millions)	
2025	$ 25	$ 10
2026	$ 17	$ 9
2027	$ 16	$ 9
2028	$ 18	$ 9
2029	$ 17	$ 8
2030 - 2034	$ 85	$ 41

NOTE 15 REVENUE

Revenue from customers is recognized when obligations under the terms of a contract are satisfied.

Sales of our Produced Oil, Natural Gas and NGLs

Revenue from sales of our oil, natural gas and NGL production is recognized upon delivery (and transfer of control) of the commodity to the customer. In certain instances, transportation and processing fees are incurred by us prior to delivery to customers. We record these transportation and processing fees as transportation costs on our consolidated statements of operations.

Our contracts with customers are generally less than a year and based on index prices. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following the month of delivery. The following table provides disaggregated revenue for sales of produced oil, natural gas and NGLs to external customers:

	Year ended December 31,		
	2024	2023	2022
(in millions)			
Oil	$ 2,255	$ 1,534	$ 1,968
NGLs	186	198	264
Natural gas	96	309	258
Sales to external customers	$ 2,537	$ 2,041	$ 2,490

We also process third-party wet gas at one of our gas processing facilities, which is sold to customers. We recognized $3 million, $15 million and $14 million included in other revenue on our consolidated statements of operations for the years ended December 31, 2024, 2023 and 2022, respectively.

Electricity Sales

The electrical output of our Elk Hills power plant that is not used in our operations is primarily sold into the California Independent System Operator (CAISO) wholesale power market. We also sold power not used in our operations to a utility under a power purchase and sales agreement (PPA) that terminated in December 2023, which included a monthly capacity payment plus a variable payment based on the quantity of power purchased each month. Revenue is recognized when obligations under the terms of a contract are satisfied; generally, this occurs upon delivery of the electricity. Revenue is measured as the amount of consideration we expect to receive based on CAISO market pricing with payment due the month following delivery. We recognize revenue using the output method and consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of capacity is made available to the customer in the case of capacity payments.

Revenue from Marketing of Purchased Commodities

From time-to-time, we enter into transactions for third-party production, which we report as revenue from marketing of purchased commodities on our condensed consolidated statements of operations. Revenues from marketing of purchased commodities results from (1) the storage or transportation of natural gas to take advantage of differences in pricing or location, (2) marketing oil sales that have resulted from third-party purchases or (3) sales of NGLs from inventory storage. To transport our natural gas as well as third-party volumes, we have entered into firm pipeline commitments. We report associated expense related to our marketing of purchased commodities in total operating expenses on our consolidated statements of operations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

	Year ended December 31,		
	2024	2023	2022
(in millions)			
Oil	$ 99	$ —	$ 1
Natural gas	128	401	314
NGLs	8	6	16
Revenue from marketing of purchased commodities	$ 235	$ 407	$ 331

NOTE 16 SEGMENT INFORMATION

We conduct our business primarily through two reportable segments: (1) oil and natural gas and (2) carbon management. We identified these segments based on the nature of their activities, the types of products sold and services to be provided. Our oil and natural gas segment explores for, develops, and produces oil and condensate, natural gas liquids and natural gas. Our carbon management segment, that we refer to as Carbon TerraVault, is expected to build, install, operate and maintain CO_2 capture equipment, transportation assets and storage facilities. Our oil and natural gas segment and carbon management segment operate exclusively in California.

Our chief operating decision maker (CODM) is Francisco Leon, Chief Executive Officer. The CODM uses segment profit or loss to assess the performance of each business, as well as our overall performance, and to make decisions about resources to be allocated to the segment, including capital investments.

Intersegment revenues relates to sales of produced natural gas to our Elk Hills power plant. Direct labor-related costs are allocated to our reportable segments based on job function. General and administrative expenses are allocated to a segment if they directly support a segment's activities. We do not allocate income taxes to our segments. We use proportionate consolidation to account for our share of oil and natural gas producing activities.

The following tables provide segment profit or loss and reconciliations of segment profit or loss to consolidated income before income taxes for the years ended December 31, 2024, 2023, and 2022.

	Year ended December 31, 2024				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation of Operating Revenues	Total
			(in millions)		
Oil, natural gas and NGL sales to external customers	$ 2,537	$ —	$ 2,537	$ —	$ 2,537
Other revenue	7	—	7	—	7
Intersegment revenues	28	—	28	—	28
Segment operating revenues	2,572	—	2,572		
Other revenues and income[(a)]				654	654
Elimination of intersegment revenues				(28)	(28)
Total operating revenues					$ 3,198

(a) Other revenues and income includes net gain from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

	Year ended December 31, 2024				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation (Income)/ Expense	Total
			(in millions)		
Segment operating revenues	$ 2,572	$ —	$ 2,572		$ 2,572
Less:					
Operating costs:					
Energy operating costs	296	—	296	(17)	279
Gas processing costs	16	—	16	—	16
Non-energy operating costs	671	—	671	—	671
General and administrative expenses	43	15	58	263	321
Depreciation, depletion and amortization	354	—	354	34	388
Taxes other than on income	207	—	207	35	242
Loss (income) from investment in unconsolidated subsidiaries	—	12	12	(2)	10
Other segment expenses[(a)]	170	67	237	—	237
Segment profit or (loss)	$ 815	$ (94)	$ 721		
Other profit or loss[(b)]				(133)	(133)
Unallocated amounts[(c)]				25	25
Income before income taxes					$ 516

(a) Amounts for our oil and natural gas segment include purchases of wet gas processed by us, power and fuel costs purchased during maintenance at our Elk Hills power plant, transportation costs, asset impairment and accretion expense, net of a gain on asset divestitures. Amounts for our carbon management segment primarily include operating lease costs, interest expense and asset impairment.

(b) Other profit or loss includes margin from purchased commodities and electricity margin.

(c) Unallocated amounts include net gain from commodity derivatives, net loss on natural gas purchase derivatives, transportation costs, interest and debt expense, other operating expenses, net, other non-operating loss, loss on early extinguishment of debt, and interest and other revenue, net of a gain on asset divestitures.

	Year ended December 31, 2023				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation of Operating Revenues	Total
			(in millions)		
Oil, natural gas and NGL sales to external customers	$ 2,041	$ —	$ 2,041	$ —	$ 2,041
Other revenue	17	—	17	—	17
Intersegment revenue	114	—	114	—	114
Segment operating revenues	2,172	—	2,172		2,172
Other revenues and income[(a)]				629	629
Total operating revenue					$ 2,801

(a) Other revenues and income includes net loss from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

	Year ended December 31, 2023				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation (Income)/ Expense	Total
			(in millions)		
Segment operating revenues	$ 2,172	$ —	$ 2,172		$ 2,172
Less:					
Operating costs:					
Energy operating costs	323	—	323	—	323
Gas processing costs	18	—	18	—	18
Non-energy operating costs	481	—	481	—	481
General and administrative expenses	42	12	54	213	267
Depreciation, depletion and amortization	205	—	205	20	225
Taxes other than on income	114	—	114	51	165
Loss from investment in unconsolidated subsidiary	—	9	9	—	9
Other segment expenses[(b)]	67	45	112	—	112
Segment profit or (loss)	$ 922	$ (66)	$ 856		
Other profit or loss[(b)]				(291)	(291)
Unallocated amounts[(c)]				115	115
Income before income taxes					$ 748

(a) Amounts for our oil and natural gas segment include purchases of wet gas processed by us, transportation costs and accretion expense, net of a gain on asset divestitures. Amounts for our carbon management segment include operating lease costs, interest expense and asset impairment.
(b) Other profit or loss includes margin from purchased commodities and electricity margin.
(c) Unallocated amounts include net loss from commodity derivatives, net loss on natural gas purchase derivatives, transportation costs, interest and debt expense, other operating expenses, net, other non-operating income, loss on early extinguishment of debt, and interest and other revenue.

	Year ended December 31, 2022				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation of Operating Revenues	Total
			(in millions)		
Oil, natural gas and NGL sales to external customers	$ 2,490	$ —	$ 2,490	$ —	$ 2,490
Other revenue	17	—	17	—	17
Intersegment revenue	153	—	153	—	153
Operating revenues	2,660	—	2,660		2,660
Other revenues and income[a]				47	47
Total operating revenues					$ 2,707

(a) Other revenues and income includes net loss from commodity derivatives, revenue from marketing of purchased commodities, electricity sales and unallocated interest and other revenue.

	Year ended December 31, 2022				
	Oil and Natural Gas	Carbon Management	Total Reportable Segments	Reconciliation (Income)/ Expense	Total
			(in millions)		
Segment operating revenues	$ 2,660	$ —	$ 2,660		$ 2,660
Less:					
Operating costs:					
Energy operating costs	323	—	323	—	323
Gas processing costs	17	—	17	—	17
Non-energy operating costs	445	—	445	—	445
General and administrative expenses	36	12	48	174	222
Depreciation, depletion and amortization	177	—	177	21	198
Taxes other than on income	111	—	111	51	162
Loss from investment in unconsolidated subsidiary	—	1	1	—	1
Other segment expenses(b)	14	28	42	—	42
Segment profit or (loss)	$ 1,537	$ (41)	$ 1,496		
Other profit or loss(b)				(140)	(140)
Unallocated amounts(c)				629	629
Income before income taxes					$ 761

(a) Amounts for our oil and natural gas segment primarily include transportation costs and accretion expense, net of a gain on asset divestitures. Amounts for our carbon management segment primarily include operating lease costs. Amounts for our carbon management segment also include $12 million to build replacement water injection facilities which will allow the diversion of produced water away from a depleted oil and natural gas reservoir.

(b) Other profit or loss includes margin from purchased commodities and electricity margin.

(c) Unallocated amounts include net loss from commodity derivatives, transportation costs, interest and debt expense, other operating expenses, net, other non-operating income and interest and other revenue.

Total assets by segment is not disclosed as it is not used by our CODM in decision-making; however, we regularly provide capital investment by segment to our CODM and have provided segment capital with a reconciliation to our consolidated capital investment for the years ended December 31, 2024, 2023 and 2022. See *Note 4 Investments and Related Party Transactions* for information on our investment in the Carbon TerraVault JV, which is part of our carbon management segment. See *Note 13 Leases* for information leases we have entered into for our carbon management business.

The following table provides capital investments for our operating segments and a reconciliation to consolidated capital investments for the years ended December 31, 2024, 2023 and 2022.

	Oil and Natural Gas	Carbon Management	Corporate and Other	Consolidated
	(in millions)			
Year ended December 31, 2024	$ 234	$ 12	$ 9	$ 255
Year ended December 31, 2023	$ 153	$ 5	$ 27	$ 185
Year ended December 31, 2022	$ 349	$ 4	$ 26	$ 379

NOTE 17 SUPPLEMENTAL ACCOUNT BALANCES

Other current assets, net — Other current assets, net include the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Net amounts due from joint interest partners[(a)]	$ 41	$ 43
Fair value of commodity derivative contracts	14	21
Prepaid expenses	28	19
Greenhouse gas allowances	27	12
Income tax receivable	50	—
All other	16	18
Other current assets, net	$ 176	$ 113

(a) Included in the net amounts due from joint interest partners are an insignificant amount of allowances as of December 31, 2024 and allowances of $3 million as of December 31, 2023.

Other noncurrent assets — Other noncurrent assets include the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Operating lease right-of-use assets	$ 105	$ 73
Deferred financing costs - Revolving Credit Facility	23	11
Emission reduction credits	11	11
Prepaid power plant maintenance	5	34
Fair value of commodity derivative contracts	16	6
Funded pension	67	2
All other	45	11
Other noncurrent assets	$ 272	$ 148

Accrued liabilities — Accrued liabilities include the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Employee-related costs	$ 184	$ 82
Taxes other than on income	100	35
Asset retirement obligations	134	99
Interest	12	18
Operating lease liability	15	15
Fair value of derivative contracts	50	8
Premiums due on commodity derivative contracts	14	21
Income taxes payable	—	18
Payables for oil and natural gas production	25	13
All other	77	57
Accrued liabilities	$ 611	$ 366

Other long-term liabilities — Other long-term liabilities includes the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Compensation-related liabilities	$ 50	$ 38
Postretirement and pension benefit plans	59	36
Operating lease liability	76	55
Fair value of derivative contracts	45	2
Contingent liability[(a)]	107	52
Other	40	18
Other long-term liabilities	$ 377	$ 201

(a) See *Note 4 Investments and Related Party Transactions* for information on the contingent liability related to the Carbon TerraVault JV.

NOTE 18 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

We have designated certain of our subsidiaries as Unrestricted Subsidiaries under the indenture governing our 2026 Senior Notes (2026 Senior Notes Indenture) and 2029 Senior Notes (2029 Senior Notes Indenture). Unrestricted Subsidiaries (as defined in the 2026 Senior Notes Indenture and 2029 Senior Notes Indenture) are subject to fewer restrictions under the indentures. We are required under the 2026 Senior Notes Indenture and 2029 Senior Notes Indenture to present the financial condition and results of operations of CRC and its Restricted Subsidiaries (as defined in the 2026 Senior Notes Indenture and 2029 Senior Notes Indenture) separate from the financial condition and results of operations of its Unrestricted Subsidiaries. The following consolidating balance sheets as of December 31, 2024 and 2023 and the consolidating statements of operations for the year ended December 31, 2024, 2023 and 2022, as applicable, reflect the consolidating financial information of CRC (Parent), our combined Unrestricted Subsidiaries, our combined Restricted Subsidiaries and the elimination entries necessary to arrive at the information for the Company on a consolidated basis. The financial information may not necessarily be indicative of the financial condition and results of operations had the Unrestricted Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheets
As of December 31, 2024 and 2023

	As of December 31, 2024				
	Parent	**Combined Unrestricted Subsidiaries**	**Combined Restricted Subsidiaries**	**Eliminations**	**Consolidated**
			(in millions)		
Total current assets	$ 437	$ 46	$ 541	$ —	$ 1,024
Total property, plant and equipment, net	14	31	5,635	—	5,680
Investments in consolidated subsidiaries	4,869	(32)	15,050	(19,887)	—
Deferred tax asset	73	—	—	—	73
Investment in unconsolidated subsidiaries	—	27	59	—	86
Other assets	113	58	101	—	272
TOTAL ASSETS	$ 5,506	$ 130	$ 21,386	$ (19,887)	$ 7,135
Total current liabilities	224	14	742	—	$ 980
Long-term debt	1,132	—	—	—	1,132
Asset retirement obligations	—	—	995	—	995
Other long-term liabilities	114	138	125	—	377
Amounts due to (from) affiliates	385	—	(385)	—	—
Deferred tax liability	113	—	—	—	113
Total equity	3,538	(22)	19,909	(19,887)	3,538
TOTAL LIABILITIES AND EQUITY	$ 5,506	$ 130	$ 21,386	$ (19,887)	$ 7,135

	As of December 31, 2023				
	Parent	**Combined Unrestricted Subsidiaries**	**Combined Restricted Subsidiaries**	**Eliminations**	**Consolidated**
			(in millions)		
Total current assets	$ 511	$ 20	$ 398	$ —	$ 929
Total property, plant and equipment, net	14	12	2,744	—	2,770
Investments in consolidated subsidiaries	2,311	(11)	1,347	(3,647)	—
Deferred tax asset	132	—	—	—	132
Investment in unconsolidated subsidiary	—	19	—	—	19
Other assets	12	36	100	—	148
TOTAL ASSETS	$ 2,980	$ 76	$ 4,589	$ (3,647)	$ 3,998
Total current liabilities	142	13	461	—	$ 616
Long-term debt	540	—	—	—	540
Asset retirement obligations	—	—	422	—	422
Other long-term liabilities	79	73	49	—	201
Total equity	2,219	(10)	3,657	(3,647)	2,219
TOTAL LIABILITIES AND EQUITY	$ 2,980	$ 76	$ 4,589	$ (3,647)	$ 3,998

Condensed Consolidating Statement of Operations
For the years ended December 31, 2024, 2023 and 2022

	Year ended December 31, 2024				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues	$ 18	$ —	$ 3,345	$ (165)	$ 3,198
Total costs and other	290	66	2,398	(165)	2,589
Gain on asset divestitures	—	—	11	—	11
Non-operating (loss) income	(92)	(21)	9	—	(104)
(LOSS) INCOME BEFORE INCOME TAXES	(364)	(87)	967	—	516
Income tax provision	(140)	—	—	—	(140)
NET (LOSS) INCOME	$ (504)	$ (87)	$ 967	$ —	$ 376

	Year ended December 31, 2023				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues	$ 21	$ —	$ 2,780	$ —	$ 2,801
Total costs and other	239	49	1,737	—	2,025
Gain on asset divestitures	—	—	32	—	32
Non-operating (loss) income	(51)	(14)	5	—	(60)
(LOSS) INCOME BEFORE INCOME TAXES	(269)	(63)	1,080	—	748
Income tax provision	(184)	—	—	—	(184)
NET (LOSS) INCOME	$ (453)	$ (63)	$ 1,080	$ —	$ 564

	Year ended December 31, 2022				
	Parent	Combined Unrestricted Subsidiaries	Combined Restricted Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues	$ 4	$ —	$ 2,703	$ —	$ 2,707
Total costs and other	177	37	1,740	—	1,954
Gain on asset divestitures	—	—	59	—	59
Non-operating (loss) income	(55)	(3)	7	—	(51)
(LOSS) INCOME BEFORE INCOME TAXES	(228)	(40)	1,029	—	761
Income tax provision	(237)	—	—	—	(237)
NET (LOSS) INCOME	$ (465)	$ (40)	$ 1,029	$ —	$ 524

NOTE 19 SUBSEQUENT EVENTS

Repurchase of 2026 Senior Notes

On February 28, 2025, we repurchased $123 million in face value of our 2026 Senior Notes at par resulting in an extinguishment loss of approximately $1 million for the write-off of unamortized debt issuance costs.

Dividends

On March 2, 2025, our Board of Directors declared a cash dividend of $0.3875 per share of common stock. The dividend is payable to shareholders of record at the close of business on March 10, 2025 and is expected to be paid on March 21, 2025.

Stock-Based Compensation

In February 2025, certain of our executives were granted an aggregate of approximately 233,922 RSUs and 350,884 PSUs. The PSUs cliff vest on the third anniversary of the grant date. The RSUs vest ratably over three years, with units vesting on the anniversary date of each grant, generally subject to continued employment through the applicable vesting dates.

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), NGLs and natural gas and changes in such quantities. Estimated reserves include our economic interests under PSCs in our Long Beach operations in the Wilmington field. All of our proved reserves are located within California.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil[(a)]	NGLs	Natural Gas	Total[(b)]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBoe)
Balance at December 31, 2021	343	41	576	480
Revisions of previous estimates[(c)]	(38)	—	(36)	(44)
Improved recovery	6	—	—	6
Extensions and discoveries	11	1	26	16
Acquisitions and divestitures	(8)	—	(1)	(8)
Production	(20)	(4)	(54)	(33)
Balance at December 31, 2022	294	38	511	417
Revisions of previous estimates[(c)]	(12)	1	51	(2)
Improved recovery	1	—	—	1
Extensions and discoveries	4	—	7	5
Acquisitions and divestitures	(12)	—	—	(12)
Production	(19)	(4)	(51)	(32)
Balance at December 31, 2023	256	35	518	377
Revisions of previous estimates[(c)]	(19)	2	(72)	(29)
Improved recovery	1	—	—	1
Acquisitions and divestitures	234	1	5	236
Production	(29)	(4)	(42)	(40)
Balance at December 31, 2024	443	34	409	545
PROVED DEVELOPED RESERVES				
December 31, 2021	282	38	510	405
December 31, 2022	251	36	458	363
December 31, 2023	223	34	445	331
December 31, 2024[(d)]	412	32	370	506
PROVED UNDEVELOPED RESERVES				
December 31, 2021	61	3	66	75
December 31, 2022	43	2	53	54
December 31, 2023	33	1	73	46
December 31, 2024	31	2	39	39

(a) Includes proved reserves related to economic arrangements similar to PSCs of 62 MMBbl, 76 MMBbl, 92 MMBbl and 111 MMBbl at December 31, 2024, 2023, 2022 and 2021, respectively.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(c) Commodity price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Long Beach operations in the Wilmington field because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data.

(d) Approximately 8% of proved developed oil reserves, 7% of proved developed NGLs reserves, 9% of proved developed natural gas reserves and, overall, 8% of total proved developed reserves at December 31, 2024 are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full production response has not yet occurred due to the nature of such projects.

2024

Revisions of previous estimates – We had net negative price-related revisions of 15 MMBoe primarily resulting from lower average realized prices in 2024 as compared to 2023, including lower natural gas realizations in 2024. These revisions included negative price-related revisions of 18 MMBoe, which were partially offset by 3 MMBoe of positive revisions from operating cost efficiencies.

We had 2 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 12 MMBoe and negative performance-related revisions of 10 MMBoe. Our positive performance-related revisions primarily related to better-than-expected well performance. Our negative performance-related revisions primarily were due to lower overall expected recovery in the San Joaquin basin.

We had 7 MMBoe of negative revisions due to lower maximum allowable surface injection pressure at the Wilmington field in the Los Angeles basin. We had 1 MMBoe of negative revisions due to the impact of AB 2716 at the Inglewood field in the Los Angeles basin. We had 2 MMBoe of negative revisions due to the retraction of the SB 1137 referendum and our analysis of sensitive receptor designations. The majority of these revisions were located in the Los Angeles Basin. We had 6 MMBoe of negative revisions associated with delays in obtaining new well drilling permits. The majority of the revisions related to permits was in the San Joaquin basin. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Improved recovery – We added 1 MMBoe related to increased well performance in certain areas in the San Joaquin basin.

Acquisitions – We acquired 236 MMBoe in the Aera Merger. See Note 2 Aera Merger for more information on this transaction.

2023

Revisions of previous estimates – We had net negative price-related revisions of 13 MMBoe primarily resulting from a lower commodity price environment in 2023 compared to 2022. Negative price-related revisions of 22 MMBoe were partially offset by 9 MMBoe of positive revisions from operating cost efficiencies.

We had 23 MMBoe of net positive performance-related revisions which included positive performance-related revisions of 38 MMBoe and negative performance-related revisions of 15 MMBoe. Our negative performance-related revisions primarily were due to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. Our positive performance-related revisions primarily related to better-than-expected well performance. The majority of these revisions were located in the San Joaquin basin.

We had 12 MMBoe of negative revisions to our proved reserves due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137. The majority of these volumes are in the Los Angeles Basin. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions – We added 5 MMBoe from extensions resulting from successful drilling and workovers in the San Joaquin, Los Angeles and Sacramento basins.

Acquisitions and Divestitures – We had a reduction of 12 MMBoe which related to our Round Mountain Unit divestiture. See Note 9 *Divestitures and Acquisitions* for more information on this transaction.

2022

Revisions of previous estimates – We had net positive price-related revisions of 6 MMBoe primarily resulting from a higher commodity price environment in 2022 compared to 2021. The price revision reflects the extended economic lives of our fields, estimated using 2022 SEC pricing. Additionally, we have experienced higher vendor-related pricing and compensation-related cost increases due to inflation.

We had 16 MMBoe of net negative performance-related revisions which included negative performance-related revisions of 31 MMBoe and positive performance-related revisions of 15 MMBoe. Our negative performance-related revisions primarily were due to wells and incremental waterflood response that underperformed forecasts and removal of proved undeveloped locations due to unsuccessful drilling results in certain areas. Our positive performance-related revisions primarily related to better-than-expected well performance and addition of proved undeveloped locations due to positive drilling results in certain areas. The majority of these revisions were located in the San Joaquin and Los Angeles basins.

We had 34 MMBoe of negative revisions to our proved reserves due to the impact of California regulatory changes and court challenges on our development plans. Of this amount, negative revisions of 20 MMBoe of proved reserves were due to the uncertainty of the outcome of the referendum and potential impact of Senate Bill No. 1137. The majority of these volumes are in the LA Basin. Negative revisions of 14 MMBoe to our proved reserves were due to challenges to Kern County's ability to issue well permits in reliance on an existing EIR for CEQA purposes. The volumes affected by these court challenges are in Kern County. See *Part I, Item 1 and 2 Business and Properties, Regulation of the Industries in Which We Operate, Regulation of Exploration and Production Activities*.

Extensions and discoveries – We added 16 MMBoe from extensions and discoveries resulting from successful drilling and workovers in the San Joaquin and Los Angeles basins.

Acquisitions and Divestitures – We had a reduction of 8 MMBoe which primarily related to our Lost Hills divestiture. See *Note 9 Divestitures and Acquisitions* for more information on these transactions.

CAPITALIZED COSTS

Capitalized costs relating to oil and natural gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	December 31, 2024	December 31, 2023
	(in millions)	
Proved properties	$ 6,343	$ 3,156
Unproved properties	1	1
Total capitalized costs	6,344	3,157
Accumulated depreciation, depletion and amortization	(953)	(601)
Net capitalized costs	$ 5,391	$ 2,556

COSTS INCURRED

Costs incurred relating to oil and natural gas activities include capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations but exclude corporate items. The following table summarizes our costs incurred:

	Year ended December 31, 2024	2023	2022
	(in millions)		
Acquisition of properties			
Proved properties	$ 2,975	$ —	$ —
Unproved properties	—	—	—
Exploration costs	2	3	4
Development costs[(a)]	207	198	389
Costs incurred	$ 3,184	$ 201	$ 393

(a) Development costs include a $28 million decrease, $44 million increase and $24 million increase in ARO (including assets held for sale) in 2024, 2023 and 2022, respectively.

RESULTS OF OPERATIONS

Our oil and natural gas producing activities, which exclude items such as asset dispositions, corporate overhead and interest, were as follows:

	Year ended December 31, 2024		2023		2022	
	(millions)	($/Boe)	(millions)	($/Boe)	(millions)	($/Boe)
Revenues[(a)]	$ 2,571	$ 64.12	$ 1,879	$ 59.98	$ 1,901	$ 57.51
Operating costs[(b)]	983	24.51	822	26.24	785	23.75
General and administrative expenses	43	1.07	42	1.34	36	1.09
Other operating expenses[(c)]	90	2.26	32	1.01	21	0.64
Depreciation, depletion and amortization	354	8.83	207	6.61	175	5.29
Taxes other than on income	207	5.16	113	3.61	111	3.36
Asset impairment	13	0.32	—	—	—	—
Accretion expense	87	2.17	46	1.47	43	1.30
Exploration expenses	2	0.05	3	0.10	4	0.12
Measurement period adjustments	(12)	(0.30)	—	—	—	—
Pretax income	804	20.05	614	19.60	726	21.96
Income tax provision[(d)]	(213)	(5.31)	(171)	(5.45)	(189)	(5.72)
Results of operations	$ 591	$ 14.74	$ 443	$ 14.15	$ 537	$ 16.24

(a) Revenues include oil, natural gas and NGL sales, cash settlements on our commodity derivatives and other revenue related to our oil and natural gas segment.

(b) Operating costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties. Operating costs includes energy, non-energy and gas processing facilities.

(c) Other operating expenses primarily include transportation costs.

(d) Income taxes are calculated on the basis of a stand-alone tax filing entity. The combined U.S. federal and California statutory tax rate was 28%. The effective tax rate for 2024 includes the benefit of marginal well tax credits. The effective tax rate for 2022 includes the benefit of enhanced oil recovery and marginal well tax credits.

STANDARDIZED MEASURE, INCLUDING YEAR-TO-YEAR CHANGES THEREIN, OF DISCOUNTED FUTURE NET CASH FLOWS

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and natural gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2024, 2023 and 2022, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2024, 2023 and 2022. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

(in millions)	December 31, 2024	December 31, 2023	December 31, 2022
Future cash inflows	$ 37,190	$ 24,813	$ 35,190
Future costs			
Operating costs[a]	(19,331)	(12,479)	(15,294)
Development costs[b]	(2,675)	(1,805)	(1,973)
Future income tax expense	(3,707)	(2,784)	(4,843)
Future net cash flows	11,477	7,745	13,080
Ten percent discount factor	(4,775)	(3,676)	(6,354)
Standardized measure of discounted future net cash flows	$ 6,702	$ 4,069	$ 6,726

(a) Includes general and administrative expenses related to our field operations and taxes other than on income.
(b) Includes asset retirement costs.

Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserve Quantities

(in millions)	2024	2023	2022
Beginning of year	$ 4,069	$ 6,726	$ 4,549
Sales of oil and natural gas, net of production and other operating costs	(1,036)	(1,604)	(1,156)
Changes in price, net of production and other operating costs	(706)	(2,829)	3,814
Previously estimated development costs incurred	234	164	228
Change in estimated future development costs	132	(47)	306
Extensions, discoveries and improved recovery, net of costs	7	99	509
Revisions of previous quantity estimates[a]	(687)	(103)	(1,041)
Accretion of discount	515	853	573
Net change in income taxes	(710)	1,029	(869)
Purchases and sales of reserves in place	4,569	(270)	(141)
Change in timing of estimated future production and other	315	51	(46)
Net change	2,633	(2,657)	2,177
End of year	$ 6,702	$ 4,069	$ 6,726

(a) Includes revisions related to performance and price changes.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Charged (Credited) to Costs and Expenses	Charged (Credited) to Other Accounts	Deductions	Balance at End of Period
2024					
Deferred tax valuation allowance	$ —	$ —	$ —	$ —	$ —
Other asset valuation allowance	$ 3	$ —	$ (3)	$ —	$ —
2023					
Deferred tax valuation allowance	$ 35	$ (35)	$ —	$ —	$ —
Other asset valuation allowance	$ 1	$ 2	$ —	$ —	$ 3
2022					
Deferred tax valuation allowance	$ —	$ 35	$ —	$ —	$ 35
Other asset valuation allowance	$ —	$ 1	$ —	$ —	$ 1

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

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our 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.

Our management has assessed the effectiveness of our internal control system as of December 31, 2024 based on the criteria for effective internal control over financial reporting described in Internal Control – Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, our management believes that, as of December 31, 2024, our system of internal control over financial reporting is effective. As described in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger,* we completed a merger with Aera on July 1, 2024. Aera was excluded from the scope of our assessment of internal controls over financial reporting as of December 31, 2024, because it was acquired in a business combination during 2024. The total assets of Aera represented approximately 45% of the related consolidated financial statement amounts as of December 31, 2024. The total revenue of Aera represented approximately 38% of the related consolidated financial statement amount for the year ended December 31, 2024.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8 – Financial Statements and Supplementary Data.*

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer supervised and participated in management's evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this Annual Report on Form 10-K. Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that as of December 31, 2024, our disclosure controls and procedures were effective and were designed to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange

Commission (SEC), and that such information is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. As disclosed in *Part II, Item 8 – Financial Statements and Supplementary Data, Note 2 Aera Merger*, we completed the Aera Merger on July 1, 2024. As part of the ongoing integration of Aera, we are in process of incorporating the controls and related procedures of Aera. Management's evaluation of our disclosure controls and procedures as of December 31, 2024 excludes an evaluation of the disclosure controls and procedures of Aera. The total assets of Aera represented approximately 45% of the related consolidated financial statement amounts as of December 31, 2024. The total revenue of Aera represented approximately 38% of the related consolidated financial statement amount for the year ended December 31, 2024.

Changes in Internal Control

Other than the on-going incorporation of Aera's controls, there were no changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act of 1934) during the three months ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

Rule 10b5-1 Trading Arrangements

During the three months ended December 31, 2024, no directors or officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

ITEM 9C DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our Proxy Statement for the 2025 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of the fiscal year ended December 31, 2024 (2025 Proxy Statement). See the list of our executive officers and related information below.

Our board of directors has adopted a code of business conduct applicable to all officers, directors and employees, which is available on our website (www.crc.com). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our code of business conduct by posting such information on our website at the address specified above.

EXECUTIVE OFFICERS

Executive officers are appointed annually by the Board of Directors. The following table sets forth our current executive officers:

Name	Employment History	Age at March 3, 2025
Francisco J. Leon	President, Chief Executive Officer and Director since 2023; Executive Vice President and Chief Financial Officer 2020 to 2023; Executive Vice President - Corporate Development and Strategic Planning 2018 to 2020; Vice President - Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director - Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	48
Clio Crespy	Executive Vice President and Chief Financial Officer since 2025; Guggenheim Securities Senior Managing Director, Investment Banking, Global Energy & Power 2020 to 2024; Evercore Managing Director 2017 to 2020; BNP Paribas VP, Investment Banking 2008 to 2017.	39
Omar Hayat	Executive Vice President and Chief Operating Officer since 2025; Executive Vice President Operations 2023 to 2025; Senior Vice President Operations 2023; Vice President of Operations for Elk Hills production complex from 2021 to 2023; Operations Manager 2019 to 2021; various technical and operational positions with the Company, Occidental Petroleum, Aera Energy and Engro Chemical (formerly Exxon Chemical) 1997 to 2019.	49
Michael L. Preston	Executive Vice President, Chief Strategy Officer and General Counsel since 2023; Executive Vice President, Chief Administrative Officer and General Counsel 2019 to 2023; Executive Vice President, General Counsel and Corporate Secretary 2014 to 2019; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	60
Jay A. Bys	Executive Vice President and Chief Commercial Officer since 2021; Private Energy Advisor 2019 to 2020 and 2015 to 2016; GenOn Energy and affiliate companies Chief Commercial Officer 2017 to 2018; Luminant Energy Vice President Origination and Capital Management 2007 to 2014; TXU, Enserch Energy various positions 1997 to 2007.	60
Chris D. Gould	Executive Vice President and Chief Sustainability Officer since 2021; Exelon Corporation Senior Vice President Corporate Strategy and Chief Innovation and Sustainability Officer 2010 to 2021; Exelon Corporation Vice President, Corporate Financial Planning and Analysis 2008 to 2010.	54

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2025 Proxy Statement. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis – Compensation Committee Report* section shall not be deemed to be "soliciting material," or to be "filed" with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

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

The information required by this item is incorporated by reference from our 2025 Proxy Statement. See also *Part II, Item 5 – Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our 2025 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Los Angeles, CA, Auditor ID: 185.

The information required by this item is incorporated by reference from our 2025 Proxy Statement.

PART IV

ITEM 15 EXHIBITS

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way the Company and investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
2.2	Amended Debtors' Joint Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed October 19, 2020 and incorporated herein by reference).
2.3	Agreement and Plan of Merger, dated February 7, 2024, between California Resources Corporation and Petra Merger Sub I, LLC, Petra Merger Sub C, LLC, Petra Merger Sub O, LLC, Petra Merger Sub O2, LLC, Petra Merger Sub O3, LLC, each a Delaware limited liability company and a wholly-owned direct subsidiary of the Company, Petra Merger Sub S, LLC, a Delaware limited liability company and a wholly-owned direct subsidiary of the Company, IKAV Impact USA Inc., a Delaware corporation, CPPIB Vedder US Holdings LLC, a Delaware limited liability company, Opps Xb Aera E CTB, LLC, a Delaware limited liability company, Opps XI Aera E CTB, LLC, a Delaware limited liability company, Green Gate COI, LLC, a Delaware limited liability company and solely for purposes of the Member Provisions (as defined in the Merger Agreement), IKAV Impact S.a.r.l., a Luxembourg corporation, Simlog Inc., a Delaware corporation, and IKAV Energy Inc., a Delaware corporation, CPP Investment Board Private Holdings (6), Inc., a Canadian corporation, OCM Opps Xb AIF Holdings (Delaware), L.P., a Delaware limited partnership, Oaktree Huntington Investment Fund II AIF (Delaware), L.P. – Class C, a Delaware limited partnership, OCM Opps XI AIV Holdings (Delaware), L.P., a Delaware limited partnership and OCM Aera E Holdings, LLC, a Delaware limited liability company. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 9, 2024 and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to the Registrant's Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 6, 2022 and incorporated herein by reference).
3.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of California Resources Corporation (filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 1, 2023 and incorporated herein by reference).

Exhibit Number	Exhibit Description
3.4	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 3.2 to the Registrant’s Registration Statement on Form 8-A filed October 27, 2020 and incorporated herein by reference).
4.1	Description of Registrant’s Securities (filed as Exhibit 4.1 to the Registrant’s Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
4.2	Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
4.3	First Supplemental Indenture to the 2026 Indenture, dated January 20, 2021, by and among California Resources Corporation, the Guarantors, Elk Hills Power, LLC, EHP Midco Holding Company, LLC, EHP Topco Holding Company, LLC and Wilmington Trust, National Association (filed as Exhibit 4.2 to the Registrant’s Current Report on Form 8-K filed January 21, 2021 and incorporated herein by reference).
4.4	Second Supplemental Indenture to the 2026 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, Aera Energy LLC, Aera Energy Services Company, Aera Federal LLC, Belridge Farms & Packing LLC, Green Gate San Ardo LLC, Terrain Technology Inc., Green Gate Intermediate LLC, Green Gate Resources E LLC, Green Gate Resources S LLC, Green Gate Resources Holdings LLC, Green Gate Resources Parent LLC, Petra Merger Sub S, LLC, the other guarantors party thereto and Wilmington Trust, National Association (filed as Exhibit 10.6 to the Registrant’s Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
4.5	Indenture, dated June 5, 2024, by and among California Resources Corporation, the Guarantors and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed June 5, 2024 and incorporated herein by reference).
4.6	First Supplemental Indenture to the 2029 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, Aera Energy LLC, Aera Energy Services Company, Aera Federal LLC, Belridge Farms & Packing LLC, Green Gate San Ardo LLC, Terrain Technology Inc., Green Gate Intermediate LLC, Green Gate Resources E LLC, Green Gate Resources S LLC, Green Gate Resources Holdings LLC, Green Gate Resources Parent LLC, Petra Merger Sub S, LLC, the other guarantors party thereto and Wilmington Trust, National Association (filed as Exhibit 10.7 to the Registrant’s Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
4.7	Second Supplemental Indenture to the 2029 Indenture, dated July 1, 2024, by and among California Resources Corporation, the Guarantors, and Wilmington Trust, National Association (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed August 22, 2024 and incorporated herein by reference).
10.1	Contractors’ Agreement, by and between the City of Long Beach, Humble Oil & Refining Company, Shell Oil Company, Socony Mobil Oil Company, Inc., Texaco, Inc., Union Oil Company of California, Pauley Petroleum, Inc., Allied Chemical Corporation, Richfield Oil Corporation and Standard Oil Company of California (filed as Exhibit 10.12 to Amendment No. 2 to the Registrant’s Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.2	Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated November 5, 1991, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, Atlantic Richfield Company and ARCO Long Beach, Inc. (filed as Exhibit 10.10 to Amendment No. 2 to the Registrant’s Registration Statement on Form 10 filed August 20, 2014 and incorporated herein by reference.
10.3	Amendment to the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated January 16, 2009, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, and Oxy Long Beach, Inc. (filed as Exhibit 10.11 to Amendment No. 2 to the Registrant’s Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.4	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to the Registrant’s Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.5	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to the Registrant’s Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.6	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.7	Warrant Agreement, dated as of October 27, 2020, by and between California Resources Corporation and American Stock Transfer & Trust Company, LLC, as Warrant Agent (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed November 2, 2020 and incorporated herein by reference).
10.8	Registration Rights Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the holders party thereto (filed as Exhibit 10.1 to the Registrant's Registration Statement on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.9	Stockholder Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the stockholders party thereto (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.10	Stockholder Agreement, dated as of July 1, 2024, by and among California Resources Corporation and the stockholders party thereto (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.11	Amended and Restated Credit Agreement, dated as of April 26, 2023, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed May 4, 2023 and incorporated herein by reference).
10.12	First Amendment to the Amended and Restated Credit Agreement, dated as of October 30, 2023, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent, Collateral Agent and an Issuing Bank (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 2, 2023 and incorporated herein by reference).
10.13	Second Amendment to the Amended and Restated Credit Agreement, entered into effective as of February 2, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 14, 2024 and incorporated herein by reference).
10.14	Third Amendment to the Amended and Restated Credit Agreement, entered into effective as of March 8, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 11, 2024 and incorporated herein by reference).
10.15	Fourth Amendment to the Amended and Restated Credit Agreement, entered into effective as of July 1, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed July 1, 2024 and incorporated herein by reference).
10.16	Fifth Amendment to the Amended and Restated Credit Agreement, entered into effective as of July 1, 2024, by and among California Resources Corporation, as the Borrower, the several lenders from time to time parties thereto and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2024 and incorporated herein by reference).
	The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.17	Form of Indemnification Agreement by and between California Resources Corporation and its directors and executive officers (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 27, 2020 and incorporated herein by reference).
10.18	California Resources Corporation 2021 Long Term Incentive Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed January 22, 2021 and incorporated herein by reference).
10.19	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.45 to the Registrant's Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.20	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.46 to the Registrant’s Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.21	Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Term and Conditions (filed as Exhibit 10.47 to the Registrant’s Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.22	Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Term and Conditions (filed as Exhibit 10.48 to the Registrant’s Annual Report on Form 10-K filed March 11, 2021 and incorporated herein by reference).
10.23	Employment Agreement by and between Mark A. McFarland and California Resources Corporation, dated March 22, 2021 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed March 22, 2021 and incorporated herein by reference).
10.24	Employment Agreement by and between Michael L. Preston and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.4 to the Registrant’s Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.25	Employment Agreement by and between Jay A. Bys and California Resources Corporation, dated June 8, 2021 (filed as Exhibit 10.5 to the Registrant’s Quarterly Report on Form 10-Q filed August 5, 2021 and incorporated herein by reference).
10.26	Employment Agreement by and between Francisco J. Leon and California Resources Corporation, dated February 23, 2023 (filed as Exhibit 10.25 to Registrant’s Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.27	Employment Agreement by and between Omar Hayat and California Resources Corporation, dated July 27, 2023 (filed as Exhibit 10.3 to the Registrant’s Quarterly Report on Form 10-Q filed on August 1, 2023 and incorporated herein by reference).
10.28	Amended and Restated Employment Agreement by and between Christopher D. Gould and California Resources Corporation, dated July 27, 2023 (filed as Exhibit 10.4 to the Registrant’s Quarterly Report on Form 10-Q filed on August 1, 2023 and incorporated herein by reference).
10.29	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.26 to Registrant’s Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.30	2023 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.27 to Registrant’s Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.31	Form of Cash Retention Bonus Agreement (filed as Exhibit 10.28 to Registrant’s Annual Report on Form 10-K filed on February 24, 2023 and incorporated herein by reference).
10.32	California Resources Corporation Employee Stock Purchase Plan (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on May 6, 2022 and incorporated herein by reference).
10.33	2024 Form of California Resources Corporation 2021 Long-Term Incentive Plan Restricted Stock Unit for Non-Employee Directors Grant Agreement (filed as Exhibit 10.6 to Registrant’s Form 10-Q filed on August 7, 2024 and incorporated herein by reference).
10.34	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.29 to Registrant’s Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
10.35	2024 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.30 to Registrant’s Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
10.36*	2025 Form of California Resources Corporation 2021 Long Term Incentive Plan Restricted Stock Unit Award Terms and Conditions.
10.37*	2025 Form of California Resources Corporation 2021 Long Term Incentive Plan Performance Stock Unit Award Terms and Conditions.
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.

Exhibit Number	Exhibit Description
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	California Resources Corporation Incentive-Based Compensation Recoupment Policy. (filed as Exhibit 97.1 to Registrant's Annual Report on Form 10-K filed on February 28, 2024 and incorporated herein by reference).
99.1*	Netherland, Sewell & Associates, Inc. Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2024.
99.2*	Insider Trading Policy.
99.3*	Business Ethics and Conduct Policies.
99.4*	Unaudited pro forma condensed combined financial statements of California Resources Corporation.
99.5*	Unaudited financial statements for Green Gate Resources, LLC.
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted in inline XBRL and contained in Exhibits 101).

* Filed herewith.
**Certain portions of this exhibit (indicated by "[*****]") have been omitted pursuant to Item 601(b)(10) of Regulation S-K

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.

CALIFORNIA RESOURCES CORPORATION

March 3, 2025

By: /s/ Francisco J. Leon

Francisco J. Leon
President,
Chief Executive Officer and Director

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.

	Title	Date
/s/ Francisco J. Leon Francisco J. Leon	President, Chief Executive Officer and Director	March 3, 2025
/s/ Clio Crespy Clio Crespy	Executive Vice President and Chief Financial Officer	March 3, 2025
/s/ Noelle M. Repetti Noelle M. Repetti	Senior Vice President and Controller and Principal Accounting Officer	March 3, 2025
/s/ Tiffany (TJ) Thom Cepak Tiffany (TJ) Thom Cepak	Chair of the Board	March 3, 2025
/s/ Andrew B. Bremner Andrew B. Bremner	Director	March 3, 2025
/s/ James N. Chapman James N. Chapman	Director	March 3, 2025
/s/ James R. Jackson James R. Jackson	Director	March 3, 2025
/s/ Christian S. Kendall Christian S. Kendall	Director	March 3, 2025
/s/ Mark A. (Mac) McFarland Mark A. (Mac) McFarland	Director	March 3, 2025
/s/ William B. Roby William B. Roby	Director	March 3, 2025
/s/ Bobby Saadati Bobby Saadati	Director	March 3, 2025
/s/ A. Alejandra Veltmann A. Alejandra Veltmann	Director	March 3, 2025

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Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held virtually at 11:00 a.m. Pacific Time on May 2, 2025. You will not be able to attend the annual meeting physically. If you wish to attend the annual meeting, you must follow the instructions under "Attending the Annual Meeting" in the proxy statement.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

American Stock Transfer and Trust Company, LLC
Shareholder Services
6201 15th Avenue, Brooklyn, New York 11219
(866) 659-2647
crc@astfinancial.com
www.astfinancial.com

Investor Relations

Company financial information, public disclosures and other information are available through our website at www.crc.com. We will promptly deliver free of charge, upon request, an annual report on Form 10-K to any stockholder requesting a copy. Requests should be directed to our Investor Relations team at our corporate headquarters address or sent to CRC_IR@crc.com.

Stock Exchange Listing

California Resources Corporation's common stock is listed on the New York Stock Exchange (NYSE). The symbol is CRC.

CRC
LISTED
NYSE

Officers

Francisco J. Leon
President and Chief Executive Officer

Jay A. Bys
Executive Vice President and Chief Commercial Officer

Clio Crespy
Executive Vice President and Chief Financial Officer

Chris D. Gould
Executive Vice President, Chief Sustainability Officer and Managing Director, Carbon TerraVault Holdings, LLC

Omar Hayat
Executive Vice President and Chief Operating Officer

Michael L. Preston
Executive Vice President, Chief Strategy Officer and General Counsel

Board of Directors

Tiffany (TJ) Thom Cepak
Chair of the Board, Member of the Finance Committee and Director since 2020

Andrew B. Bremner
Member of the Compensation Committee, Finance Committee, Sustainability Committee and Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2021

James N. Chapman
Chair of the Compensation Committee and Finance Committee and Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2020

James R. Jackson
Member of the Sustainability Committee and Director since 2024

Christian S. Kendall
Chair of the Nominating and Governance Committee, Member of the Audit Committee and Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2024

Francisco J. Leon
President, Chief Executive Officer and Director since 2023

Mark A. (Mac) McFarland
Chair of the Board of Directors of Carbon TerraVault Holdings, LLC and Director since 2020

William B. Roby
Chair of the Sustainability Committee, Member of the Audit Committee, Nominating and Governance Committee and Compensation Committee and Director since 2020

Bobby Saadati
Member of the Finance Committee and Director since 2024

Alejandra (Ale) Veltmann
Chair of the Audit Committee, Member of the Nominating and Governance Committee and Director since 2021

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A DIFFERENT KIND OF ENERGY COMPANY

Sustainability